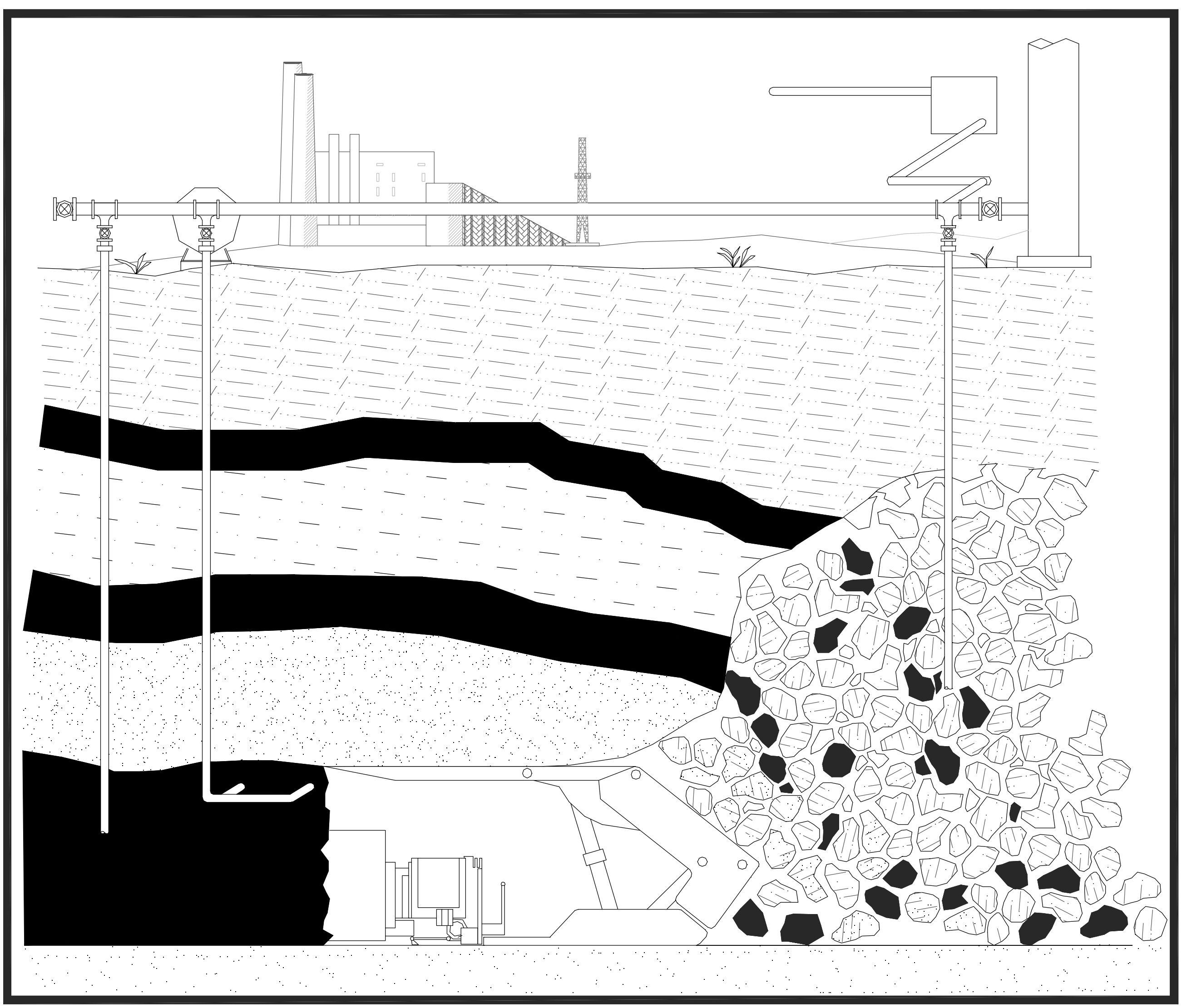
WHITE PAPER:

Guidebook on Coalbed Methane Drainage for Underground Coal Mines

April 1999

Mine Safety ◆ Increased Coal Reserves

Reduced Downtime ◆ Reduced Water Problems



Ventilation Power Cost Savings ◆ Worker Comfort

Reduced Dust Problems ◆ Reduced Development Costs

ACKNOWLEDGEMENTS

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DISCLAIMER

ABSTRACT

Coal mine methane, a byproduct of mining operations, can be recovered to provide various types of benefits to a mining company. These benefits include, but are not limited to, reduced ventilation costs, downtime costs, and production costs; and the ability to use the recovered gas as an energy source, either at or near the mine site or by injecting it into a commercial gas pipeline system. There are many variables that play a part in the decision to implement a coal mine methane drainage project. Mining companies can employ basic decision-making logic to determine the feasibility of draining and/or using methane at specific coal mines. This handbook outlines a logical procedure for underground coal mining operations to evaluate the drainage and use of coal mine methane.

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INTRODUCTION

Over the past few decades, emissions of methane from coal mines have increased significantly because of higher productivity, greater comminution of the coal product, and the trend towards recovery from deeper coal seams. Under current federal coal mine regulations, methane must be controlled at the working faces and at other points in the mine layout. This has traditionally been performed using a well-designed ventilation system. However, this task is becoming more difficult to achieve economically in modern coal mines. In addition, scientists have established that methane released to the atmosphere is a major greenhouse gas, second only to carbon dioxide in its contribution to potential global warming. In order to improve mine safety and decrease downtime as a result of methane in the mine openings, many mines are now using a degasification system to extract much of the coalbed methane from their seams before or during mining. Methane drainage offers the added advantages of reducing the ventilation costs, reducing the development costs of the mine, reducing the global warming threat, and allowing a waste product to be productively utilized.

This handbook outlines a logical procedure for underground coal mining operations to evaluate coalbed methane resources as a byproduct. This byproduct can be gathered to produce three levels of benefits to a mining company, depending on the market potential of the methane. The benefit levels are as follows:

(1) The methane is gathered from the coal seam to reduce ventilation costs, downtime costs, production costs, and shaft development costs or to benefit from increased coal resources. All of these benefits are achieved internal to the mining operation and can be easily analyzed by the mining company. These benefits will be outlined in this guidebook in some detail.

(2) The coalbed methane is extracted from the seams to be mined and is utilized as a local energy resource to heat buildings, dry coal output from the coal preparation facility, generate electrical power, power vehicles by compressing the gas, or other local uses. This category of use will be outlined in expanded form later in this document.

(3) The extracted methane can be upgraded, if necessary, or immediately compressed and introduced into a commercial gas pipeline system. This may provide the highest possible benefit to the mining company providing that the methane is of high quality and the mine location is near a gas pipeline. With this option, the value of the methane as an energy resource may be very large and it can make a significant contribution to profits.

The material in this guidebook is an attempt to provide a look at all aspects of the methane handling problem for a coal mining company. It examines coalbed methane extraction methods, the economic benefits of gathering the methane, and the possible avenues for utilization of the methane. It is hoped that this publication will aid mining companies in obtaining the highest levels of benefits achievable for their methane resources while simultaneously enhancing mine safety.

METHANE DEGASIFICATION METHODS

By law, methane concentrations must be below 1.0% at the working faces (CFR; 75.323b), below 1.5% where the return air split enters another air split (CFR; 75.323c), and below 2.0% where a bleeder enters the main return (CRF 75.323e). With increasing coal production and depth of coal mines, traditional ventilation methods are not always the most economical methods of handling methane in the coal seam. Degasification systems have been developed that recover the gas before, during, or after mining. The degasification methods, coupled with mine ventilation, may be the most economical method of keeping methane concentrations low in many mines. Degasification methods that have been used in the U.S. include vertical wells, gob wells, horizontal boreholes, and cross-measure boreholes. Pertinent variables related to each of these methods are outlined in the following sections. Further descriptions of these methods can be found in Hollub and Schafer (1992) and Rogers (1994).

Additional coalbed methane extraction procedures have been applied in other countries of the world or have been applied only in an experimental mode. These methods are outlined in the final subtopic below titled “Other Degasification Methods.”

Vertical Wells

The term “vertical well” is generally applied to a well drilled through a coal seam or seams and cased to pre-drain the methane prior to mining. The wells are normally placed in operation 2 to 7 years ahead of mining and the coal seam is hydraulically fractured to remove much of the methane from the seam. A vertical well may look like that shown in Fig. 1. The water in the coal seams must be removed to provide better flow of gas. This water is separated and must then be treated and/or disposed of in an environmentally acceptable manner.

To enhance the flow of gas from a vertical well, either hydraulic fracturing or open-hole cavity completions are generally used. These are shown in Fig. 2. Open-hole cavities are produced by physical or chemical means and are serviced by means of a perforated pipe through the seams to insure sufficient flow. They have been used primarily in the San Juan Basin coal seam gas operations. In the Appalachians, hydraulic fracturing operations are commonly used to enhance gas flow from the wells. Both vertical and horizontal fractures are produced in the coal seam. However, these fractures generally do not seriously affect the mineability of the coal seams if the roof is competent.

Vertical wells recover high-quality gas from the coal seam and the surrounding strata. The gas quality is ensured in most cases because the methane will not be diluted by ventilation from the mine. The total amount of methane recovered depends on site-specific conditions such as the gas content of the coal seams and surrounding strata, permeability of the geologic materials, the drainage time, the amount of negative head applied, and other variables of the geologic and extractive systems. Vertical wells can recover 50% to 90% of the gas content of the coal and are normally placed in operation two to seven years before mining commences.

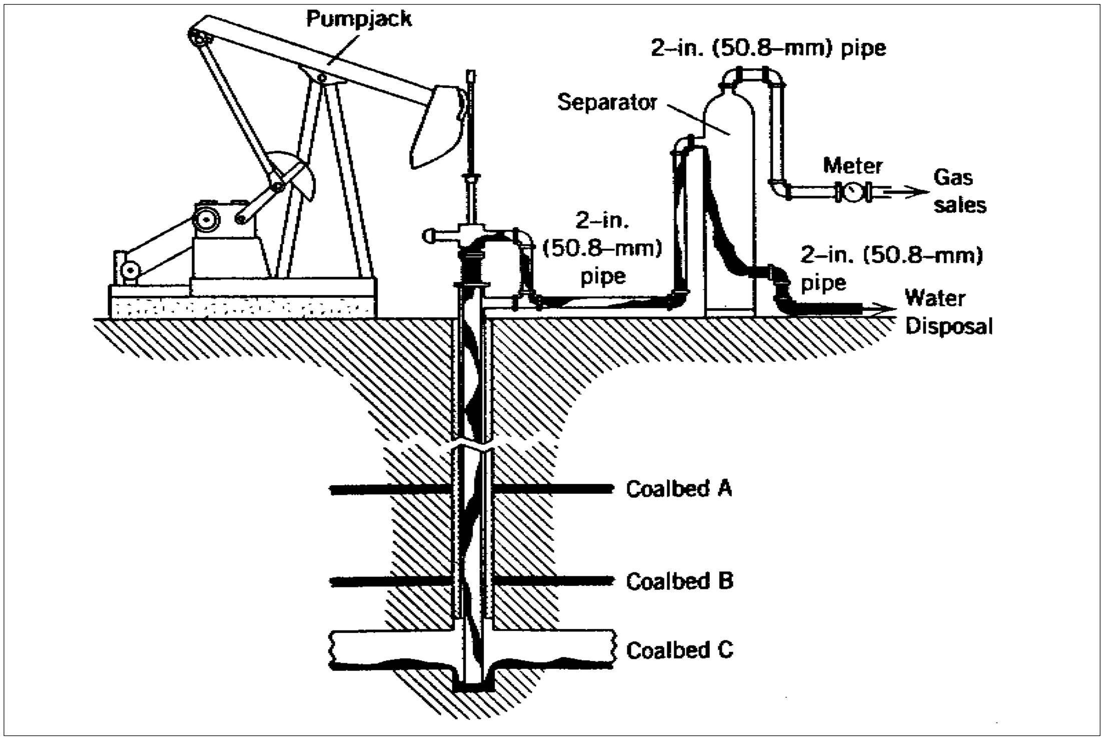

Figure 1. Typical vertical well setup. Source: Hartman et al., 1997. Copyright 1997, John Wiley & Sons, Inc. Reprinted with permission of John Wiley & Sons, Inc.

Vertical wells offer an advantage over other methods because they can be applied to multiple coal seams simultaneously. These wells produce greater gas yields that can make them commercially economic as well as further reduce the potential for gas influx into the operating mine. To provide an adequate flow of gas into a vertical well, a number of well completion methods are used. The most common is to hydraulically fracture the coal seam and use proppants to insure an adequate flow of methane from the fractures. The second most common procedure is to create an open cavity in each coal seam to enhance the flow characteristics. In either case, the well casing is perforated at each coal seam encountered to provide for the flow of gas into the wellbore.

Vertical wells provide the most consistent supply of high-quality gas of all the common drainage methods. The calorific value of the gas is normally greater than 950 Btu/standard cubic foot (950 Btu/scf), making it acceptable for use in natural gas pipelines. It is also relatively easy to use this method to insure a steady quantity of gas to a pipeline customer. The only major problems with vertical wells are the possibilities of having nitrogen or carbon dioxide above allowable limits or significant amounts of water that must be properly handled. Either of these problems can be handled using available technology, but each will add to the costs of extracting the methane.

At least five coal companies are currently using vertical wells for drainage of their coalbed methane ahead of mining. The method has the disadvantages of being required years ahead of the mining process and of requiring surface access. These are minor problems if the methane content of the seam or seams is high or if the potential for market returns is high.

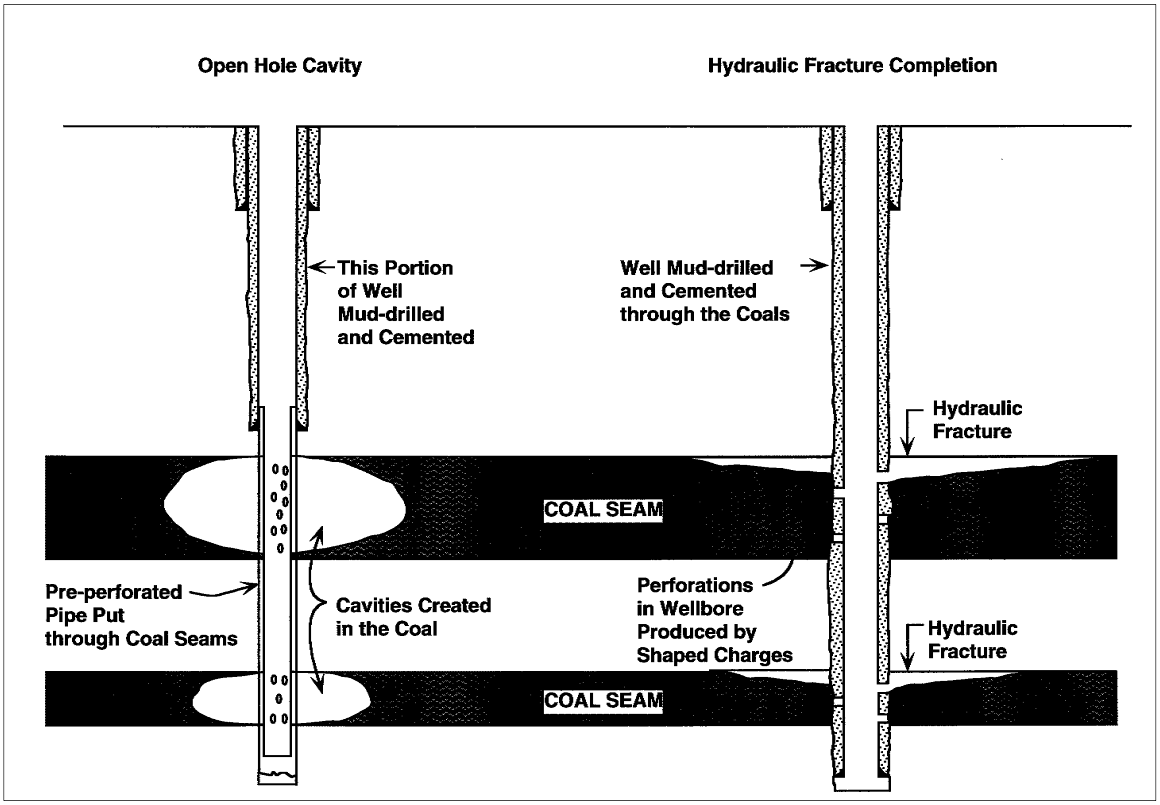

Figure 2. Common completion methods for vertical wells (modified after Logan, 1993).

Gob Wells

The designation "gob well" refers to the type of coalbed methane (CBM) recovery well that extracts methane from the gob areas of a mine after the mining has caved the overlying strata. Gob wells differ from vertical wells in the sense that they are normally drilled to a point 10 to 50 feet above the target seam prior to mining, but are operated only after mining fractures the strata around the wellbore. The methane emitted from the fractured strata then flows into the well and up to the surface. The flow rates are mainly controlled by the natural head created by the low-density methane gas or can be stimulated by blowers on the surface.

Figure 3 shows an active gob well used to drain methane from the gob area of a mine and a second well drilled above the active mining section that will be placed in operation as the longwall moves under the well. The number of gob wells on a longwall panel varies considerably with the number being a function of the rate of mining and the gas content of the caved strata.

Gob wells can recover 30% to 70% of methane emissions depending on geologic conditions and the number of gob wells within the panel. Gas quality varies, but is higher at the beginning of production and can be improved somewhat by controlling the flow rate. Methane extracted from gob wells can be blended with gas from other sources to be compressed and put in a pipeline. However, as the caloric value of the gas deteriorates, the gas from gob wells may require enrichment to allow it to retain its pipeline quality. Alternately, gob well gas can be utilized in internal combustion engines or gas turbines to produce electricity or it can be used to heat buildings or dry coal in the coal-cleaning facility. These applications require a caloric value of only about 300 Btu/scf.

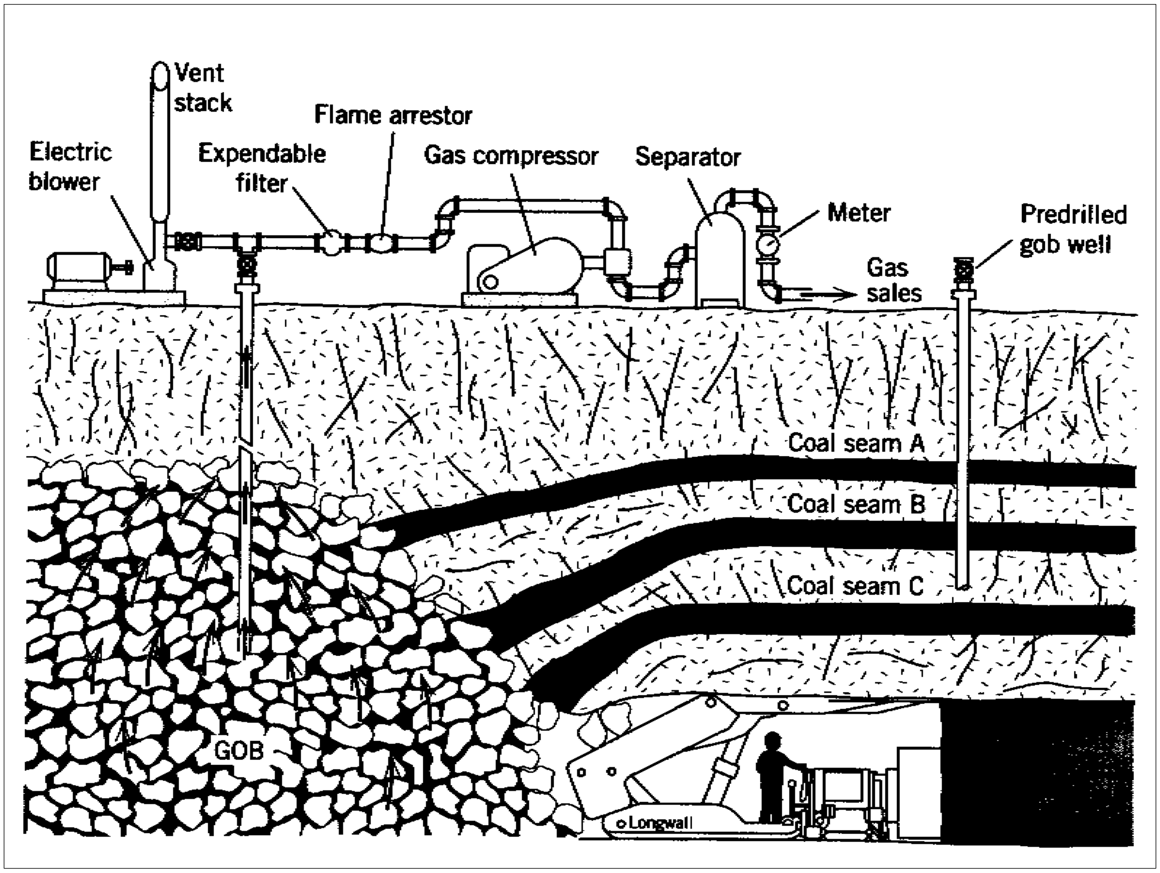

Figure 3. Gob well setup above an active longwall section. Source: Hartman et al., 1997. Copyright 1997, John Wiley & Sons, Inc. Reprinted with permission of John Wiley & Sons, Inc.

Gob wells are the most effective method of reducing methane content in rapidly moving longwall faces. They have several disadvantages when compared to vertical wells: lack of consistently high gas content, relatively short production life, and application only to overlying strata. For this reason, gob wells will often contribute significantly to mine safety and productivity but not to reduction of greenhouse gases. This occurs because the gases are often vented to the atmosphere because of a Mine Safety and Health Administration restriction against flaring of the methane. Therefore, it is important for mining companies to develop more uses for the gas from gob wells.

Currently, more than 20 mines use gob wells as part of their methane control plan. At least seven are utilizing the gas as pipeline-quality fuel, while a few others are utilizing the product gas for medium-quality applications such as electrical power generation and local heating applications. The remainder are venting the gas to the atmosphere because of a lack of an identified economic use for the gas.

Horizontal Boreholes

Horizontal holes are drilled into the coal seam from development entries in the mine. They drain methane from the unmined areas of the coal seam shortly before mining, reducing the flow of methane into the mining section. Because methane drainage occurs only from the mined coal seam and the period of drainage is relatively short, the recovery efficiency of this technique is low. Normally, about 10% to 20% of the methane is recovered from the drilled area. However, the gas quality is high and can be utilized as a pipeline product in most cases. Higher recoveries can often be achieved in room-and-pillar sections by drilling longer holes far in advance of mining.

When horizontal boreholes are used underground, a gas transmission line and a vertical borehole are generally used to carry the methane to the surface. Figure 4 shows such a system with both a discharge stack and a connection to a pipeline. A more typical pattern of boreholes is shown in Fig. 5. In this figure, the holes are drilled parallel to each other through panels to be mined in the near future. The spacing of the boreholes is a function of the permeability and gas content of the seam and is at its minimum when the most urgency is attached to increasing the percentage of methane drained previous to the initiation of mining in the panels. Some details of a successful system are provided by Aul and Ray (1991).

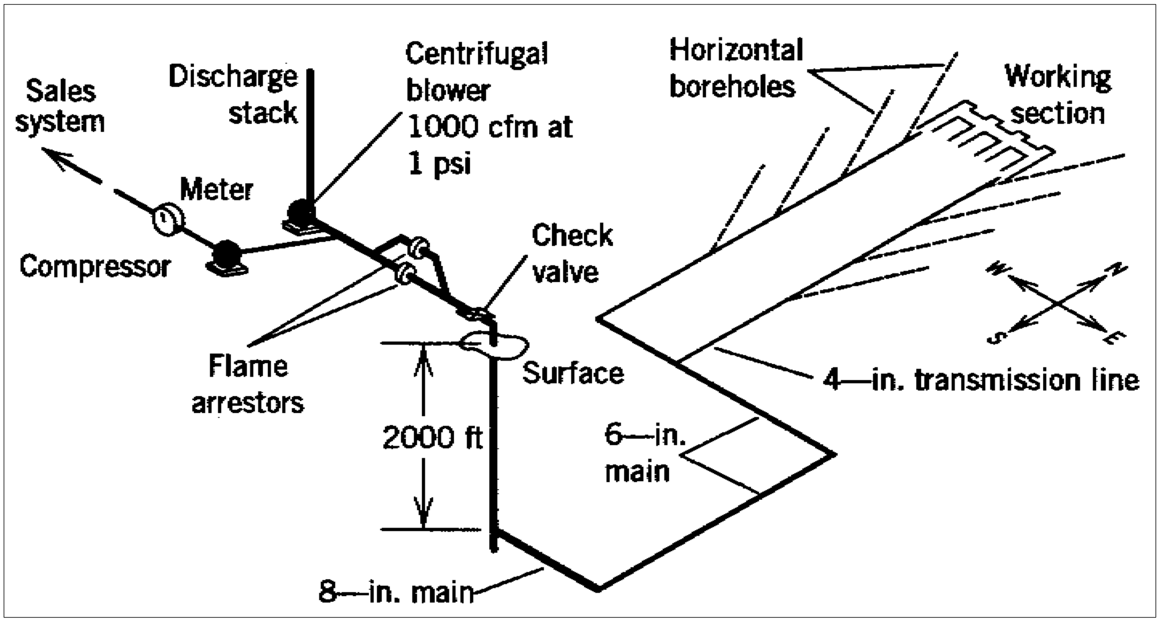

Figure 4. Layout of a horizontal borehole methane drainage system showing both in-mine and surface facilities. Source: Hartman et al., 1997. Copyright 1997, John Wiley & Sons, Inc. Reprinted with permission of John Wiley & Sons, Inc.

Horizontal boreholes are drilled in both relatively short and relatively long lengths, depending upon the needs of the mine. Shorthole drilling can be performed using light-duty drills, and longer hole length can be achieved with heavier drilling rigs. Horizontal holes up to 1000 feet in length are normally drilled into longwall or room-and-pillar panels a few months to a year ahead of mining the panels so that the methane content can be reduced before mining. To utilize a horizontal borehole system, each borehole must be placed on a manifold so the gas can be transported to the surface by pipeline. The drainage efficiency using horizontal holes less than 1000 feet is generally less than 20%. As a result, these horizontal holes are used in longwalls only where methane concentrations are high and permeabilities are relatively low. About 15 mines use these shorter holes as part of their methane recovery plan.

Long horizontal boreholes are utilized in about ten mines. These holes are longer than 1000 feet and must therefore be placed in the coal seam using drilling technology that allows for guidance of the drill to keep the borehole in the coal seam for several thousand feet. Boreholes up to 4000 feet in length have been drilled in this fashion. This allows a larger block of coal to be drained for a longer period. Up to 40% recovery efficiency can be achieved using this method. Like horizontal shortholes, these boreholes are normally connected by manifold to a pipeline so the gas can be transported to the surface.

The caloric value of gas derived from horizontal boreholes is generally high enough in to be used as a pipeline product. In addition, the quantity is normally regulated by the nature of the boreholes, making the flow of gas rather constant in many cases. However, while many mines use horizontal boreholes to recover methane, only a portion market the gas.

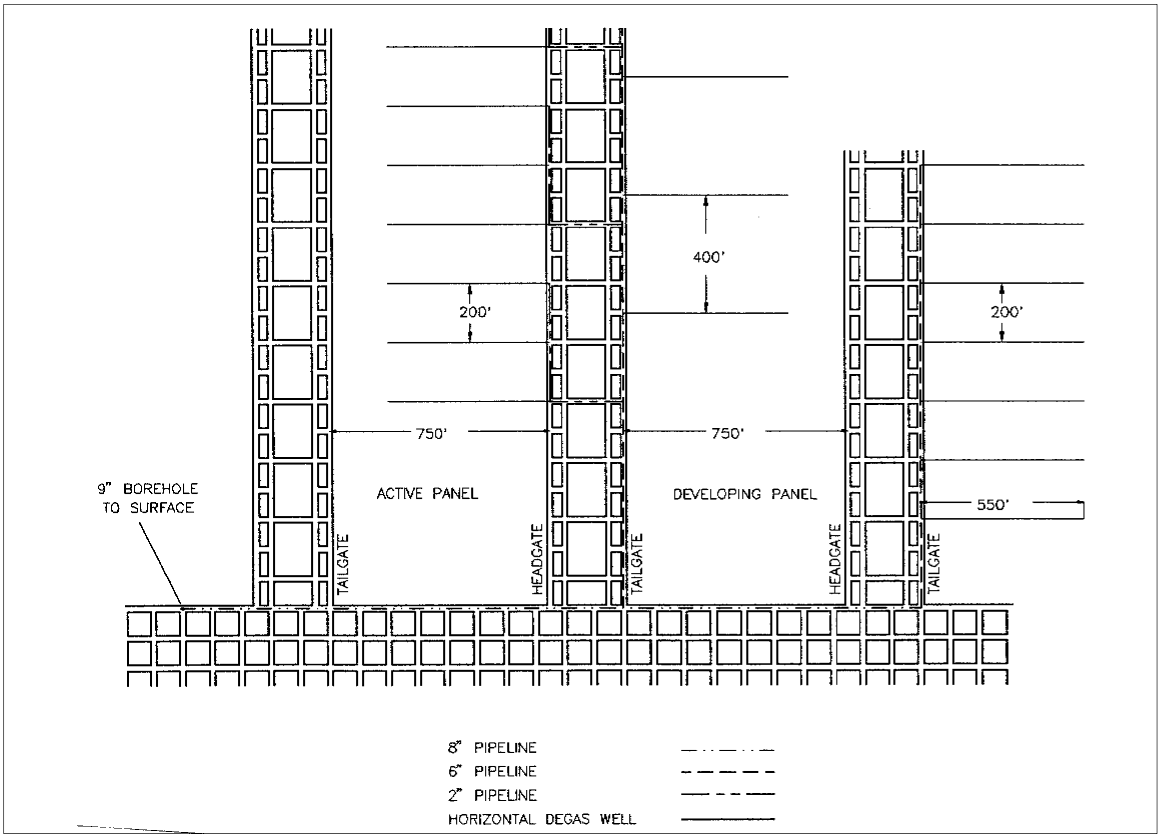

Figure 5. Typical horizontal borehole pattern and pipeline arrangement at a longwall mine (Aul and Ray, 1991).

Cross-Measure Boreholes

Cross-measure boreholes are drilled at an angle to the strata, normally from existing mine entries. The boreholes are strategically placed above areas to be mined with the goal of predraining the overlying strata and exhausting gas from the gob area. Like horizontal borehole systems, the individual holes must be connected to a main pipeline which ordinarily is coursed through a vertical borehole to the surface. Figure 6 shows the patterns of holes for a set of longwall panels. Figure 7 illustrates the angular nature of the boreholes and the piping necessary to operate the individual borehole and connect it to the main pipeline. The angle at which the holes are drilled is a function of the height and width of the geologic zone to be drained and the location of the entry from which the holes are to be drilled.

The cross-measure system for CBM drainage has been most successful in Eastern Europe. Its usefulness in those geologic areas indicates that it has potential elsewhere. The method has been utilized on an experimental basis in the U.S. (Cervik, Garcia, and Goodman, 1985; Baker, Garcia, and Cervik, 1988). However, the general ease of using gob holes in the U.S. makes the economic use of cross-measure boreholes less probable. Cross-measure systems will most likely be attractive in the U.S. only if surface access is impossible.

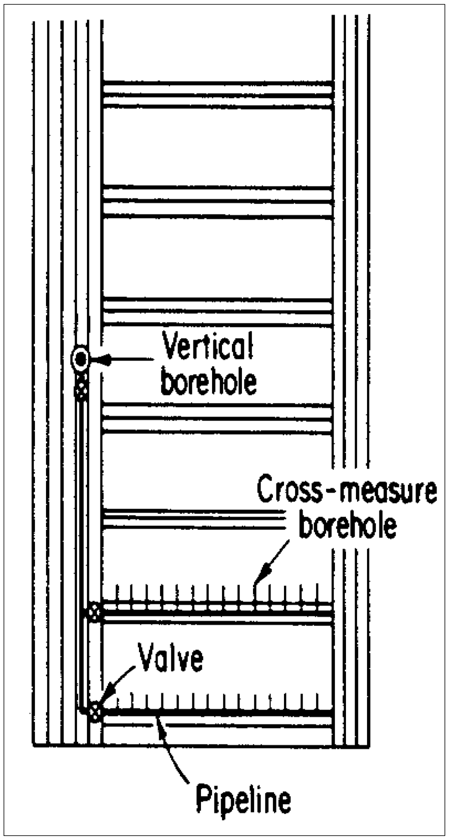

Figure 6. Pattern of cross-measure boreholes (Baker, Garcia, and Cervik, 1988).

Other Degasification Methods

A variety of additional methods for drainage of methane from coal measures has been attempted or used on a production basis throughout the world. These include the packed-cavity methods, the superjacent methods and the method of using directional drilling. Additional information regarding these methods can be obtained from the publications by Davidson, Sloss, and Clarke (1995) and Thakur (1997). These methods may eventually find some use in the U.S. though they currently have not done so.

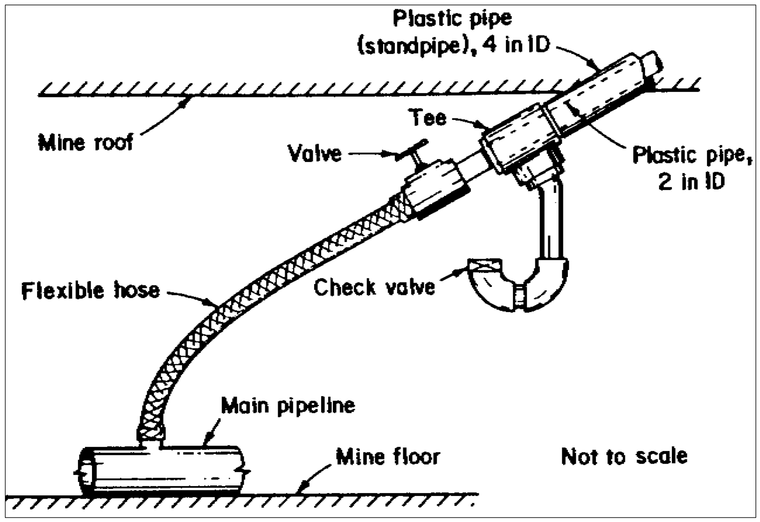

Figure 7. Diagram indicating angular orientation and pipeline connection for a cross-measure borehole (Baker, Garcia, and Cervik, 1988).

MINING-RELATED ECONOMIC BENEFITS OF COALBED METHANE DRAINAGE

There are many mining benefits that accrue from a methane drainage system. Methane drainage systems can: (1) enhance coal productivity because of less frequent downtime or production slowdowns caused by gas; (2) decrease fan operating costs because of reduced air requirements for methane dilution; (3) reduce shaft sizes and number of entries required in the mains, (4) increase tonnage extracted from a fixed-size reserve as a result of shifts of tonnage from development sections to production sections; (5) decrease dust concentrations due to reduction of velocities at the working face; (6) improve mine safety resulting from lower methane contents in the face, returns, gobs and bleeders; (7) reduce problems with water; (8) improve worker comfort through reduction of velocities in the working faces; and (9) provide miscellaneous other benefits.

Most of these benefits can be estimated by means of engineering or economic analyses of the degasification efforts and comparison of the mining costs with and without the drainage systems in place. Other benefits, such as reduced dust concentration, improved safety, or improved worker comfort, are difficult to estimate. While they constitute a real and significant benefit, they may have to be written off in any economic estimation effort.

Each of the mining-related economic effects will be described in the upcoming sections. Those for which benefits have been measured will be outlined in greater detail. Those for which the benefits are either too difficult to estimate or are dependent on the specific operation will be outlined without making any attempt at quantification.

Reduced Downtime

Enhanced coal productivity is probably the most significant benefit to be obtained from methane pre-drainage systems where coalbed methane is encountered in significant quantities. The benefits come in the form of added production that occurs when downtimes or slowdowns resulting from high methane occurrences are avoided using methane drainage. The value of such a benefit can be extremely large when one considers that the value of coal that comes off a longwall in a shift averages about $100,000 to $200,000 for an average modern longwall. Any lost production due to gasouts results in a sizable cost (around $200 to 400 per minute of downtime in this case). The significance of this cost can be realized when it is considered that downtime of up to 11,000 minutes per month for a single longwall have been reported in the literature (Aul and Ray, 1991) and that many longwalls will experience slowdowns in production as well as times where the longwall is completely down due to the methane. The economic benefit of having a methane drainage system will thus be substantial in such a case.

A similar economic advantage will occur in room-and-pillar operations that have the possibility of production interruptions due to methane emissions in the working sections. With continuous miner productivities continually rising, the downtime cost can be in the range of $50 to $100 per minute of downtime averted by a well-designed gas drainage system. While the economic return attributed to reduced downtime is lower per minute of downtime, the proportion that this benefit constitutes of the overall benefit in room-and-pillar mining will normally be higher than in longwall mining because the remainder of the economic benefits are smaller than in longwall.

Ventilation Power Cost Savings

The power costs associated with the mine ventilation system will ordinarily be the second most significant benefit associated with the addition of a methane drainage effort. Several papers have outlined costs associated with ventilating high-methane mines (Mills and Stevenson, 1989; Kim and Mutmansky, 1990; Aul and Ray, 1991). In many mines, ventilation to ensure continuous production is quite expensive. Methane drainage would normally be used instead of increased ventilation because the overall costs associated with drainage will be lower than the costs associated with ventilation. One of the references (Aul and Ray, 1991), cites situations where a drainage system reduced the ventilation requirements for methane dilution to about half, thus greatly reducing the ventilation power costs. Kim and Mutmansky (1990) performed ventilation analysis to determine power cost savings over a 20-year mine lifetime for several scenarios. One conclusion was that a mine with 400 ft^3/ton of methane using vertical wells to reduce its ventilation quantities can reduce its power cost an estimated $11,000,000 over 20 years. An additional estimated $3,000,000 in ventilation power costs can be saved if horizontal holes are used in addition to vertical holes in the same mine. Actual costs will, of course, be a function of the mine size, the ventilation plan, the electrical power costs, and the actual air quantities saved in a particular mine ventilation network.

A more recent study (Wang, 1997) has verified the significant nature of the ventilation power cost savings. This analysis was conducted in a manner similar to the previous study with more attention paid to the leakage and bleeder ventilation quantities. The analysis verified that methane drainage could be an economic endeavor in longwall operations based on the mining-related benefits alone if the gas released during mining was 400 ft^3/ton or more. The study by Wang also included a preliminary economic analysis of the ventilation cost savings in room-and-pillar mining. In this category of the study, the economic analysis of the power cost analysis showed significant savings for room-and-pillar mining as well. However, since other categories of benefits were not as significant, the power cost savings were a much greater percentage of the total cost benefit for methane drainage systems. Thus, power cost savings were even more important in continuous mining systems than they are in longwall.

Reduced Development Costs

Another important issue in assessing the costs and benefits associated with mining is the possibility that a reduction in the ventilation requirements will result in a reduced requirement for development openings. This can result in two types of cost benefits. The first benefit is the reduction in the size and number of shafts and other development openings connecting the coal seam to the surface. This can at times result in a significant level of economic savings. The second benefit results if the coal from the development entries of a mine is more costly on a $/ton basis than that in the production sections. In a longwall mining operation, the coal produced from development openings will be much more costly than that produced in a longwall panel. These can be significant as shown in previous studies (Kim and Mutmansky, 1990). In this situation, the reduction in cost for each ton of coal shifted from a development section to a production section will be a benefit of the drainage system that made the shift possible.

The second type of production cost savings may not occur in all coal operations. They are achieved only if two conditions are met: (1) the number of development entries is reduced as a result of utilization of a methane drainage system, and (2) the cost/ton of coal from a production section is less than that from a development section. Generally the cost savings in this category are easy to quantify by technical personnel familiar with the mining operation.

Increased Reserve

The benefit of an increased reserve is also provided in a mining operation when a gas drainage system allows for a reduced number of entries in the development of mains, submains, headgates, and tailgates of mining layouts. This results in an increased number of tons of coal that can be extracted from a fixed-size coal block. The extra tonnage is derived from the fact that only about 50% of the coal in development sections is extracted while production sections may extract 85% to 95% of the coal under good conditions. The extra coal extracted when this occurs is an economic benefit of significant value under many conditions. Thus, it should be evaluated as a potential benefit in every operation where degasification is considered.

The economic value of an increased reserve can be valid in either a longwall or a room-and-pillar operation. The economics of the added reserve are easier to visualize for a longwall because a shift of coal from development to production will almost assuredly result in extra tonnage being available. These benefits have been evaluated for longwall mining by Kim and Mutmansky (1990) and Wang (1997). For longwall mining, these benefits will be 8% to 59% of overall benefits, depending on market and other conditions (Wang and Mutmansky, 1998). For room-and-pillar mining, the added reserve is not as certain to occur. The determining factor is whether or not the production sections have a higher recovery than the development sections. This is quite variable and depends primarily on the type of equipment utilized and the pillaring method.

Mine Safety

The effect of a methane drainage system on the safety of a mining system will certainly result in positive benefits (Ely and Bethard, 1989). Any high-methane operation will incur a higher level of hazardous operating conditions than an equivalent mine with a methane drainage system in place. However, the ability to measure the economic benefits that result is quite complicated due to the fact that the probability of a mine accident resulting from methane in the mine will be difficult to measure accurately. Because this probability is the key variable in determining the costs or benefits, the determination of cost benefits will be quite difficult. Thus, the accounting for any cost benefits related to mine safety may be better set aside in the cost/benefit analysis of a methane degasification system.

Reduced Dust Problems

The relationship between gas drainage activities and the costs of providing proper dust control in a mining section is another possible source of cost benefits from gas drainage. For example, the reductions in dust levels may be significant if the ventilation on a longwall is reduced from above 100,000 cfm to 50,000 cfm. This results in the air velocity being reduced from about 2000 fpm to 1000 fpm at the worst position along the face. Previous measurements by Mundell et al. (1980) indicate that the dust concentrations at a longwall face normally rise if the air velocity increases above 600 fpm as shown in Fig. 8. This results in added costs for dust controls, additional dust sampling, and less comfortable work conditions. However, obtaining a reliable estimate of this cost will often be quite difficult. The curve shown in Fig. 8 may not be accurate for today's longwalls because better dust control technology is available. In addition, relating the dust concentrations and costs are also a problematic step. Thus costs and benefits of a degasification project in this area may be quite difficult to obtain.

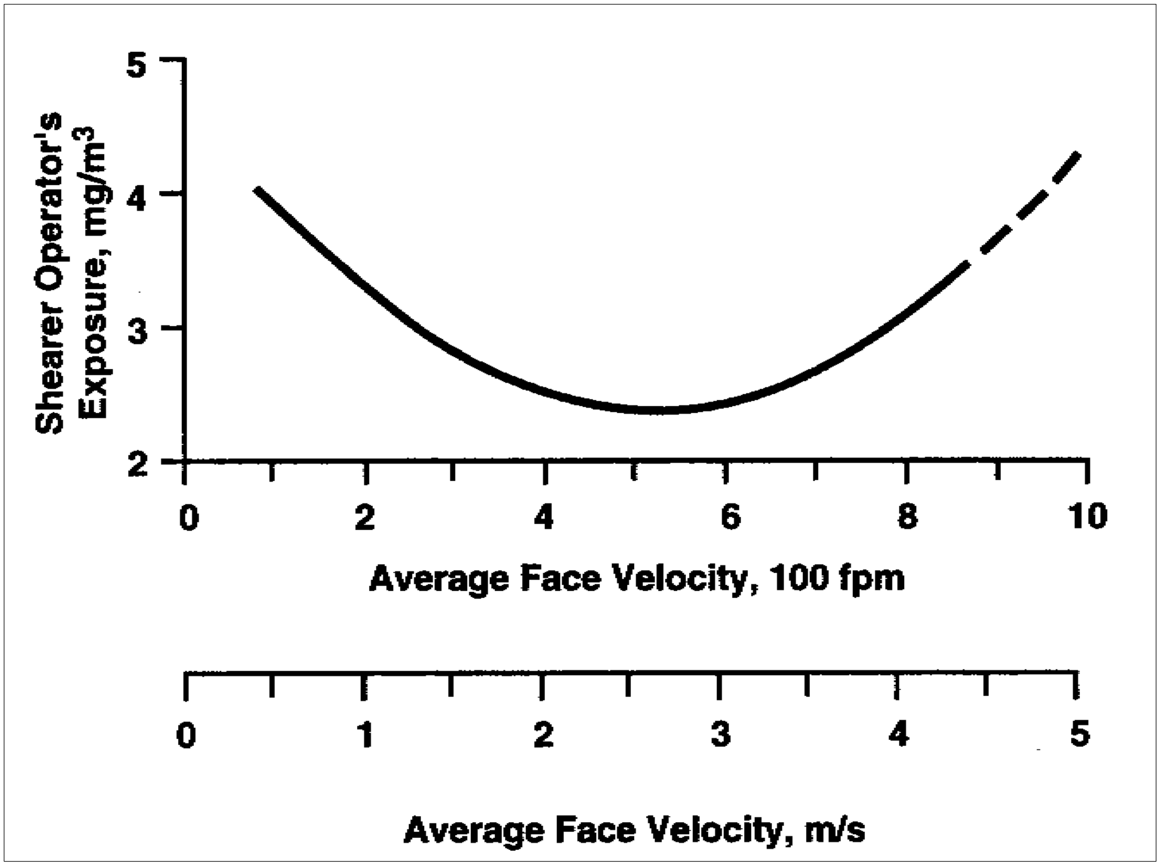

Figure 8. Shearer operator dust exposure vs. average face air velocity (Mundell et al. 1979).

Reduced Water Problems

The presence of water in coal mine roof strata can be a costly source of delays in some underground mining operations. The most sizeable delays will ordinarily be encountered in the development sections of the mine and will be quite variable depending upon the geologic parameters of the roof strata. The water in the roof, when occurring in conjunction with high methane contents, can be mitigated by a methane drainage system. The statistics of downtime reductions in such mines may vary, but the reduction in water downtimes may be of notable economic value. In addition, the economic benefits would be easy to measure in most mines.

One description of such a benefit has been outlined by Reese and Reilly (1997) for a Pennsylvania longwall mine. In this operation, a 63% reduction in water downtimes and a 16% reduction in methane downtimes was achieved when the gas drainage wells were utilized. In the results published, the downtimes as a function of total production time were not reported. However, the percentage of downtimes need not be large to produce a significant cost benefit. Thus, any mine with such water problems should calculate the impacts due to a reduction in downtime due to water when considering a degasification system.

Worker Comfort

The level of comfort of work in a mining environment deteriorates if high air velocities are required to keep methane contents below the regulatory limits. The difficulty of working in an air velocity above 600 ft/min is that ordinary tasks become more difficult and the high velocities will generate more dust. In some longwall sections, for example, the high velocities downward of the shearer result in the transported dust creating a “sand blasting” effect on the exposed skin of workers that is both unpleasant and a hazard to their eyes. While the number of personnel working downwind of the shearer is generally small, the hazards involved are both significant and avoidable.

Any attempt at attaching a cost benefit to the worker comfort aspect of a drainage system will be a difficult accounting task. While such a benefit clearly exists, it will be both complicated and expensive to estimate. As a result, the benefit may be better left unquantified.

Miscellaneous Other Benefits

Other benefits, not so easily quantified, are also achieved using a methane drainage system. These include the good will that derives from better personnel and public relations. Every mining company is subject to a significant level of suspicion by employees and the general public at times. This can often be a residual doubt that exists from past experiences or a result of some unsatisfactory event that occurred. Any company should, therefore, support an activity that its workers and the general public view as possessing a positive contribution to society. Mining companies who are harvesting methane and utilizing it should logically claim the public relations benefits that go with that activity. An enlightened management will certainly wish to capture these hard-to-measure, but real, benefits.

STRATEGIES AND COSTS OF APPLICATION

This section outlines a variety of issues that affect the matching of methane degasification activities with the methane emissions that occur in underground mining systems. Of particular interest will be the patterns of methane emission that occur in each type of mining operation, the corresponding collection characteristics of each of the primary gas drainage techniques, and the related costs of installing and utilizing methane drainage systems. Efficient methods for extracting the methane for a variety of methane emission situations are suggested.

The pattern of methane release from the coal seam or seams will ordinarily be controlled primarily by the mining method, the location of the gas in the seam and the surrounding strata, and the permeability of the relevant geologic materials. If the degas method is chosen considering these variables, the gas extraction can be both adequate and cost-efficient. It is therefore worthwhile outlining some of the specific patterns of methane release that can be encountered and gas extraction systems to handle these problems.

Longwall Mining

In longwall mining, the distribution of methane releases coming out of the coal and surrounding strata is controlled in part by the geometry of the panels and the subsidence that occurs during the mining process. The methane coming from the overlying and underlying sediments will normally play a major part in the overall release pattern. An ideal illustration of this is outlined in Fig. 9. In this pattern, the company recorded the downtime due to the methane in a single large longwall panel. The data was plotted against the coal production from the panel to determine the effects of the methane on the ability to mine coal. The data pattern was chosen for use here because it shows the strong relationship between downtime and production.

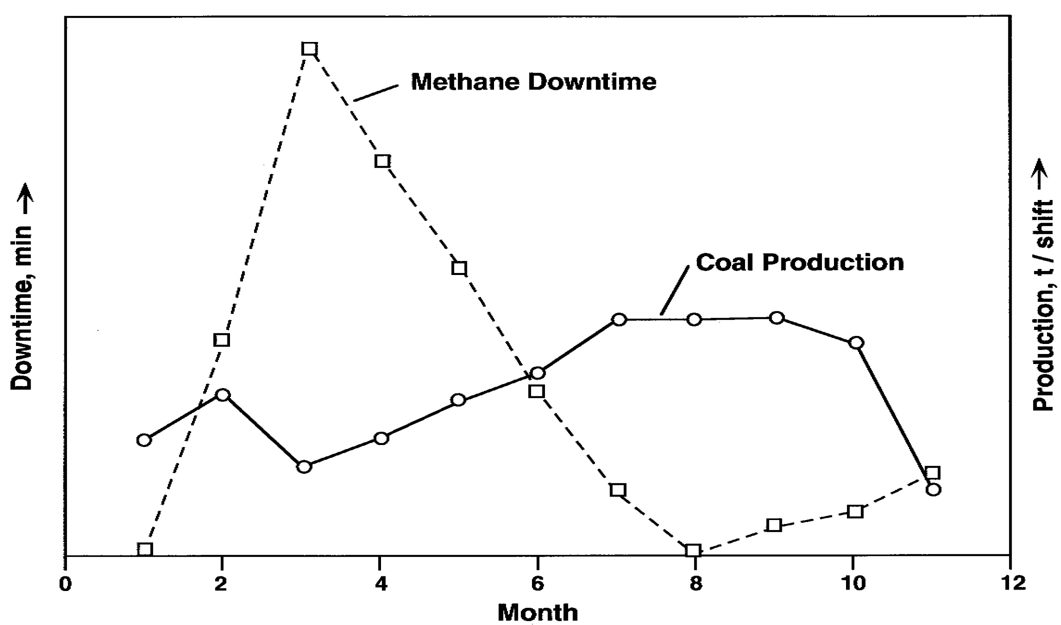

Figure 9. Methane downtime versus coal production on a longwall panel (Mutmansky and Wang, 1998).

A more typical pattern is shown in Fig. 10. In this graph, three successive longwall panels are represented. The longwall moves are shown on the graph along with the methane downtime, total downtime, and production. The total downtime represents the total shift time that the longwall is not operating due to mechanical repair and maintenance, roof support activity, and downtime due to excess methane in the face, return, or bleeder return entries. This graph shows that the methane downtime is likewise a function of the location in the panels and that production is more or less inversely proportional to the total downtime. However, the pattern is not as clearly defined as that in Fig. 9. The methane downtimes seem to rise to a peak a relative short time after the initiation of the panel. However, the pattern is not as totally consistent as one would hope. Instead, the pattern of downtimes requires a mitigation approach aimed at an average pattern of methane emissions.

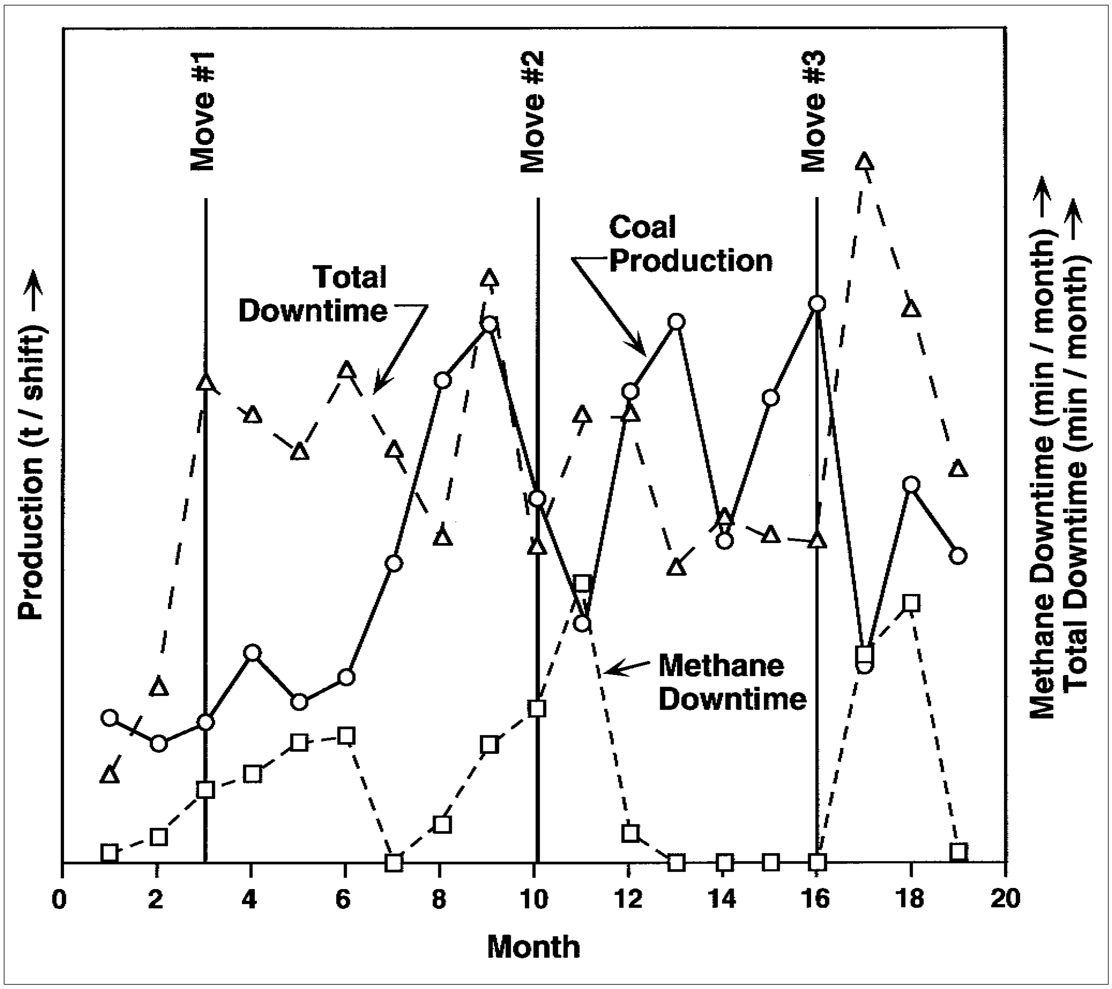

Figure 10. Coal production versus methane and total downtime for three successive longwall panels (Mutmansky and Wang, 1998).

In attempting to meet the gas problems of a longwall that emits methane in a pattern similar to that shown, several options are available. The typical options used are:

1. gob wells
2. vertical wells
3. vertical wells plus gob wells
4. vertical wells, gob wells, and horizontal holes in the seam.

The chosen option is based primarily on the quantities of gas to be extracted and the permeability of the pertinent strata. The actual application of each drainage technique used will be most efficient if the pattern of emissions is matched by the pattern of wells drilled to extract the methane.

A number of helpful sources of information are available in the literature to aid in design of the well pattern. The area of the coal seam to be drained by a vertical well has been studied by Zuber, Kuuskraa, and Sawyer (1990). This study applied to vertical wells in the Oak Grove field in Alabama and found that well spacings varying from 40 to 160 acres were optimal under the assumed conditions with smaller acreage being optimal for lower permeabilities (below 10.0 md). Typical well spacing in the Alabama coal fields is about 40 acres with 3 to 7 wells placed in each projected longwall panel. Similar results were reported by Richardson, Sparks, and Burdett (1991).

An additional design consideration of significance in choosing gob well locations is to position wells off-center. The reasoning for off-center wells is outlined in several references (Diamond, Jeran, and Trevits, 1994; Diamond, 1995). The higher density of wells at the beginning of the longwall is often used in some seams to better intercept the higher emissions to be encountered and to take advantage of the tensile conditions that enhance the coalbed methane recovery in the initial stages of the longwall caving operation.

On the other hand, some methane-related references recommend a higher density of gob wells at the end of the longwall panel (English, 1997). The reason for this is the thickness of overlying seams and their gas contents will cause the maximum emission to occur at different places along the length of the longwall panel. It is therefore a good idea to investigate the emission pattern before the final well placement design is adopted. It is fairly clear that different patterns of emission can and will occur.

When longwalls have very high concentrations of gas within the seam to be mined, horizontal wells may be implemented to further reduce gas before mining. Horizontal holes are generally utilized in two different ways. The first is to drill long holes ahead of the coal faces to drain methane. This is often referred to as longholing and requires a drilling rig with control over the drill string so that the holes can be reliably kept within the coal seam. To utilize a longhole drilling operation, the drill is normally set up in existing mine openings. Holes of 3 to 3 1/2 inches in diameter are then drilled from 1000 feet to 2000 feet ahead of the current openings to begin draining the methane well ahead of time. Figure 11 shows how such a set of drill holes can be used to extract a portion of the methane ahead of a set of development entries. Because the holes must be steered in both the horizontal and vertical planes, the drilling technology must be sophisticated to ensure success in proper placement of the holes (Thakur and Dahl, 1982).

The second method of drilling horizontal holes involves shorter hole length. These holes are often drilled with simpler drills. The drills need not possess guidance systems like those used for longholing. A typical layout (Aul and Ray, 1991) for horizontal holes in longwall panels was previously shown in Fig. 5. The horizontal holes were driven at 200-foot to 400-foot spacings depending how long the holes were active in drainage before mining. Short holes of this type are normally 2 to 3 inches in diameter and are driven at spacings of 100 to 400 feet. In longwall panels, they are terminated at 50 or more feet from breakthrough.

Room-and-Pillar Mining

The traditional room-and-pillar mining system will encounter methane in a number of ways. Normally, the methane will be a result of methane releases from within the coal as the entries and crosscuts are developed. Horizontal drilling is often used to address this problem. The methane can also emanate from the roof during the pillar recovery process. Gob wells are preferred for this situation. Therefore, it will vary depending on whether development or retreat mining is being pursued.

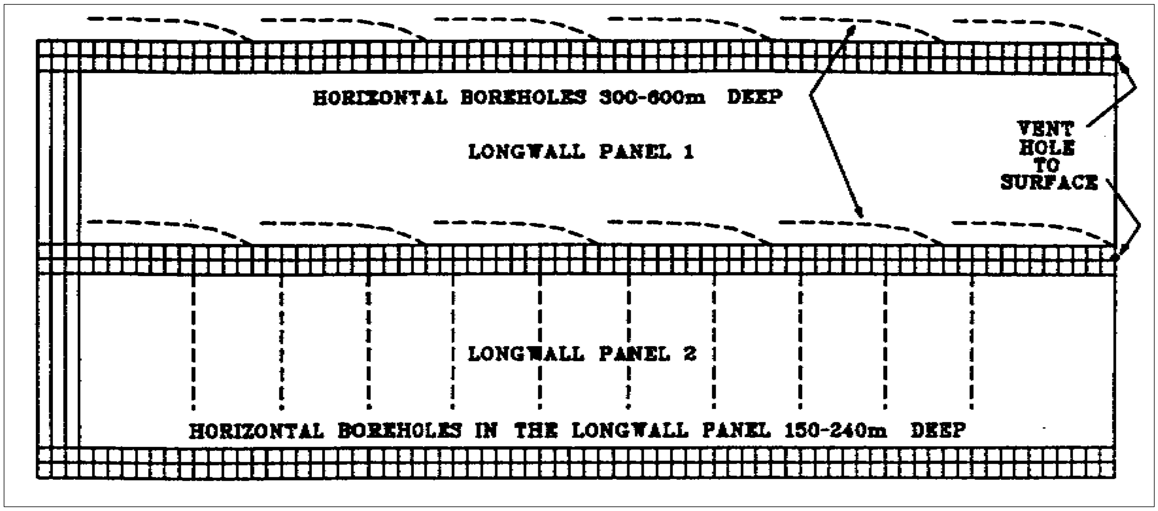

Figure 11. Diagram showing use of long curved horizontal boreholes and shorter parallel boreholes in longwall mining.

The pattern of emissions for one room-and-pillar mining operation is shown in Fig. 12. The figure shows the methane downtime, total methane handled by the ventilation system, and the coal production for a continuous miner room-and-pillar system used strictly as a development operation. The pattern shown includes the average values for 43 months of operation and includes several moves of the production system from one section to another.

In this operation, the methane handled does not appear to be associated with the start of completion of panel development. Company records indicated the occurrences of high methane were a function of the geologic variables associated with the coal seam, particularly faults in the roof, floor feeders, or other geologic discontinuities. Because the apparent causes for methane downtime were recorded, it was easy to relate these occurrences to the periods when methane handled was high. Section production values were not seriously affected in all cases, but the coal production values plotted in Fig. 12 are considerably less when the methane emissions are high.

The drainage options for room-and-pillar mining systems may be somewhat different than those for longwall mining. If the emissions are expected to be uniform throughout the coal block, then the same three options may be used. However, if the emissions are controlled in part by localized geologic features, the mine management may wish to utilize horizontal holes as the primary degasification strategy.

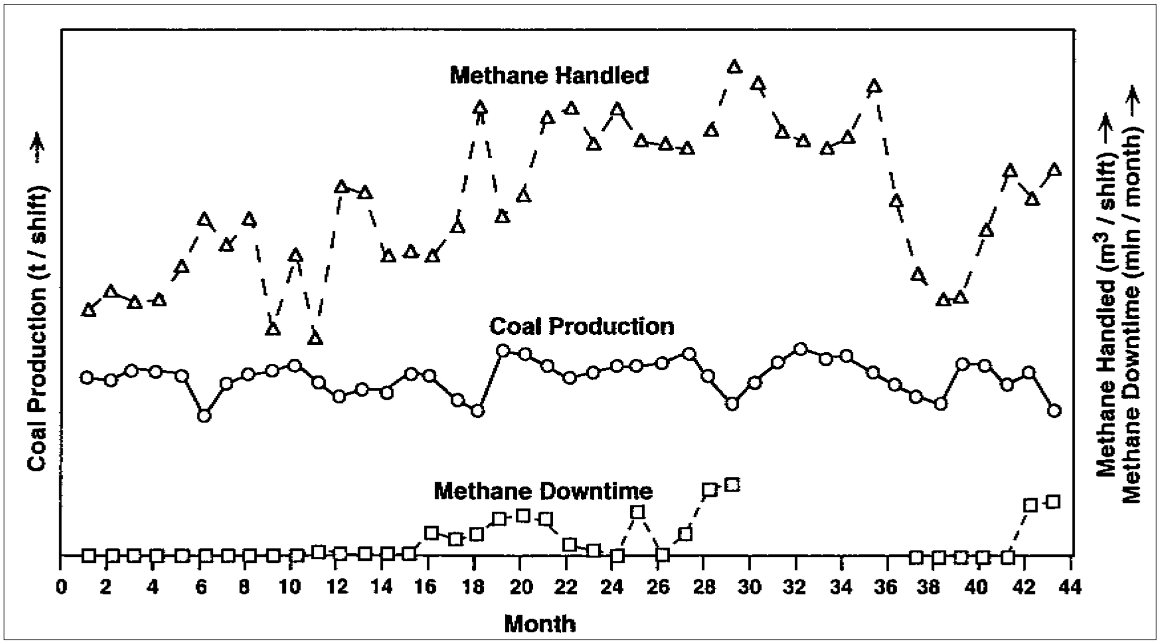

Figure 12. Coal production versus methane variables for a room-and-pillar operation (Mutmansky and Wang, 1998).

As in longwall mining, the design of the methane drainage system should be governed by the quantity of methane being generated, the pattern of emissions, the mining-related costs associated with the methane, and the potential for obtaining a market income from the gas generated. The drainage system design may require adjustment on a continuing basis to ensure that the methane capture is nearly optimal as the mine develops over time.

Cost Considerations

In setting up a CBM recovery program, the costs of putting the system into operation will play a major role in determining the economic values of the project. For the mining company entering the methane recovery field for the first time, numerous reliable sources of information are available that will help in the estimation of well costs. This comes about because more than 6000 vertical CBM wells have been completed with much of the data being available through public records. In addition, costs for drilling horizontal and cross-measure boreholes for methane recovery have appeared fairly often in the literature. As a result, a reasonably good estimate of the methane recovery costs can usually be obtained.

Table 1 displays a compilation of costs that are derived from a number of publications. The numbers represent a range of costs that would apply to the three major CBM fields: the San Juan Basin, the Black Warrior Basin, and the Central Appalachian Basin. It should be noted, however, that most of the costs will vary based on the geographic basin, ruggedness of the topography, the depth of the wells, legal and physical accessibility of well sites, and other variables that change the resources that must be used.

In assessing the differences in cost between the major coal areas, a number of sources can be utilized. However, a summary of cost variations has been compiled by the U.S. Environmental Protection Agency (USEPA, 1993) for both vertical and gob wells. These are provided in Table 2. It should be noted that the principal cost variations are due to depth of the wells and costs of surface rights in the various mining areas. However, other costs enter into the picture as well. This is the reason for low, medium and high cost levels in the table. This table will provide only rough cost estimates. More accurate cost estimates will require interaction with drillers and landowners.

Other costs that must be estimated in the setting up of a CBM drainage system can include costs for gathering lines, compressors, processing plants, and main pipelines to place the gas into a gas pipeline. For power generation, the system often must estimate costs for gathering lines, gas turbines or internal combustion engines, transmission lines to carry power to a network connection, and ducts for utilization of ventilation and in the generators if that is feasible. A summary of the costs is outlined in Table 3.

The final major element of cost is the disposal of water from vertical wells. The water disposal cost is normally a function of the water quality. Some vertical wells have been drilled into seams that yield relatively clean and unpolluted water. One example of this is the Blacklick Coalbed Methane Project now operated by Belden and Blake in southern Indiana County, Pennsylvania. In this case the water removed from the wells is relatively pure with little in the way of pollutants. It can be disposed of in surface streams after a minor aeration and sedimentation process without degradation of the streams. However, most deep vertical wells will produce water that is saline in nature or that contains other chemical pollutants. The water will thus have to be treated or injected via wells into some deep geologic sediments in order to dispose of it without environmental harm.

A good review of the options for treating and disposal of well water from CBM projects has been presented by Lee-Ryan, Fillo, and Tallon (1991). At the low end of the cost scale, aeration followed by sedimentation will produce clean water in some cases. This procedure is used in the Blacklick Coalbed Methane Project with great success. Other chemical processes are reverse osmosis and electrodialysis, each being much more expensive than aeration. The next most expensive method is deep-well injection with disposal into sediments, which will not affect water supplies. The most expensive method is evaporation of the water and disposal of the evaporites. This is generally quite expensive because of the energy requirements for the evaporation process. A summary of the projected costs for these methods is presented in Table 4. The range of capital and operating costs for water disposal are provided in Table 5. While the costs of utilizing these methods are substantial in cases, at least a company using CBM wells will have a variety of methods at their disposal.

Table 1
Range of Costs for Coalbed Methane
Drainage Methods

Drainage Method		**Expenditure Items**	**Costs ($/well)**	**References**
Vertical Wells	Capital Costs	Geological, Geophysical and Acquisition	20,000-30,000	Logan, Clark, and McBane (1987) Zuber, Kuuskraa, and Sawyer (1990) Fraser, Peden, and Kenworthy (1991) Kuuskraa and Boyer (1993) Rogers (1994); Willis (1991); Petzet (1997)
		Well Drilling & Completion	110,000-300,000	
		Lease Equipment, incl. Gas Gathering	60,000-120,000	
		Water Disposal System	40,000-50,000	
		Well Stimulation	60,000-80,000	
		Engineering and General and Administrative	30,000-100,000	
		Total	320,000-640,000	
	Operating Costs	20,000-40,000 ($/yr)		
Gob Wells	Capital Costs	Project Planning, Surveying and Mapping, Surface Rights	17,900-31,000	Kline, Mokwa, and Blankenship (1987) Niederhofer and Lambert (1987) Baker, Garcia, and Cervik (1988) Lambert (1989) Hanby (1991)
		Site and Road Preparation	56,000-122,000	
		Well Drilling and Completion	112,000-182,000	
		Lease Equipment	72,000-120,000	
		Supervision, Office, General Overhead	50,000-80,000	
		Total	307,900-535,000	
	Operating Costs	20,000-40,000 ($/yr)		
Horizontal boreholes	Capital Costs	Cost per unit length	33-66 ($/m) 10-20 ($/ft)	Baker, Garcia, and Cervik 1988) Kim and Mutmansky (1990) Kravitz (1996)
	Operating Costs	105,000-640,000 ($/yr/project)		
Cross-measure boreholes	Capital Costs	Cost per unit length	125-184 ($/m) 38-56 ($/ft)	
	Operating Costs	105,000-640,000 ($/yr/project)		

(1) Costs reflect the range for the three major coalbed basins in the continental United States.
Some reviewers have stated that these costs are conservatively high. Readers may wish to take this into account.

Table 2
Capital Costs for Gob Wells
(per well costs)

GOB WELLS[a]

Basin	Low	Medium	High
Central Appalachian	$80,000	$130,000	$190,000
Northern Appalachian	$60,000	$110,000	$170,000
Illinois	$50,000	$100,000	$160,000
Warrior	$90,000	$140,000	$200,000
Western	$100,000	$150,000	$210,000

VERTICAL WELLS[b]

Basin	Low	Medium	High
Central Appalachian	$60,000	$125,000	$225,000
Northern Appalachian	$50,000	$140,000	$205,000
Illinois	$45,000	$115,000	$195,000
Warrior	$90,000	$190,000	$290,000
Western	$320,000	$450,000	$580,000

[a]Capital costs for gob wells include all costs for surface drilling rights, site development and preparation, and costs for drilling, completing and equipping the wells.

[b]Capital costs for vertical wells include all costs for surface drilling rights, site development and preparation, drilling, completing and equipping the wells and hydraulic fracture treatment.

Note: Some reviewers have stated that these costs are conservatively high. Readers may wish to take this into account.

Sources: USEPA (1993); USEPA (1990); ICF Resources (1990b); ICF Resources (1989); Ammonite Resources (1991); Hunt and Steele (1991); Spears and Associates (1991); Baker et al. (1998).

Table 3
Range of Costs for Coalbed Methane Utilization

Utilization Processes	Expenditure Items		Cost, $	References
Pipeline Injection	Capital Costs	a. Gathering lines (wellhead –central compressor) b. Compressor(s) c. Processing/Treatment d. Gathering lines to Main Commercial Pipeline	10,000–100,000 per well 180-200 per mcf/day 10-30 per mcf/day 200,000-950,000 per mile	USEPA, 1993; USEPA, 1990; ICF Resources, 1990a; Sykes, 1989; ICF Resources 1990b; True, 1990; Willis, C., 1991; Willis, C., 1995
	Operating Costs	a. Compressors(s) b. Processing/Treatment c. Enrichment	0.06-0.08 per mcf 0.02-0.04 per mcf 1.00-2.00 per mcf	USEPA, 1993; USEPA, 1992b; ICF Resources, 1990; True, 1990
Power Generation	Capital Costs	a. Gathering lines between wellhead and generator b. Gas Turbine c. Off-site Transmission d. Ducts for Utilization of Ventilation Air	10,000-40,000 per well 800-1,200 per kw installed 100,000-500,000 per project 400,000-600,000 per project	USEPA, 1993; Sturgill, 1991; ICF Resources, 1990c; Wolfe and Maxwell, 1990; Energy Systems Associates, 1991
	Operating Costs	Gas Turbine	0.02-0.02 per kWh	USEPA, 1993; ICF Resources, 1990c; Wolfe and Maxwell, 1990; Energy Systems Associates, 1991

Table 4 Cost Estimates for CBM Water Treatment/Disposal Technologies[a]		
Technology	**Annual Cost[b] ($/yr)**	**Unit Cost[b] ($/Barrel)**
Aeration/Sedimentation	28,000 - 48,000	0.03 - 0.06
Reverse Osmosis	411,000	0.47
Electrodialysis	447,00	0.51
Deep-Well Injection	706,000	0.81
Evaporation	1,872,000	2.15
[a]Source: Lee-Ryan, Fillo, and Tallon (1991) [b]Based on a 20-year project life and a 10% discount rate		

Table 5 Range of Costs for Coalbed Methane Well Water Disposal			
Utilization Processes	**Expenditure Items**	**Cost, $**	**References**
Water Disposal System	Capital Costs	0.30 - 3.30/barrel	USEPA, 1993; ICF Resources, 1990b; Lee-Ryan et al., (1991); Evans et al., 1991; Ortiz, 1992; Luckianow et al., 1991
	Operating Costs	0.02 - 1.00 per barrel	USEPA, 1993; ICF Resources, 1990b; Lee-Ryan et al., 1991; Evans et al., 1991, Ortiz, 1992

Cost/Benefit Example

To illustrate the costs and benefits of a drainage system on a longwall mining operation, a hypothetical mining system is assumed here and will be analyzed for three different scenarios. In each case, the assumption is that a 13,610 ft by 21,860 ft block of coal is to be mined using three continuous miners and a longwall in a systematic manner. The mains and submains are provided with an optimal number of entries for each individual system and the shafts are also sized to keep air velocity at an optimal level. The criteria used to set air velocities are outlined in the parameter definitions below.

The primary mine and ventilation parameters assumed to be operative during each of the three scenarios are outlined in the following list:

Depth of seam: 1500 ft
Thickness of seam: 6 ft
Coal density: 82.5 lb/ft^3
Entries and crosscuts on 90-ft centers
All entries 6 ft by 20 ft
No geologic discontinuities
Optimal entry velocity: 600 to 1100 ft/min
Optimal shaft velocity: 2000 to 2500 ft/min
Power costs: $0.05/kWh
Ventilation friction factors:
    Intakes: 60 x 10^{-10} lb min^2/ft^4
    Returns: 80 x 10^{-10} lb min^2/ft^4
    Shafts: 20 x 10^{-10} lb min^2/ft^4
Resistances used:
    Stoppings: 2500 x 10^{-10} in min^2/ft^6 per 100 stoppings
    Gob: 10^{-7} in min^2/ft^6
Longwall production: 3300 tons/shift
Continuous miner production: 1000 tons/shift
Raw coal value: $20/ton
Continuous miner costs: $19/ton
Longwall costs: $14/ton
Methane content: 600 ft^3/ton
Methane recovery: 60% (with 5 years lead time)
Methane value: $0 (methane not marketed)
Pillars in mains, submains, and gate entries not recovered

Wang (1997) determined ventilation costs for several scenarios using the parameters above. He investigated nine stages in the mine lifetime and analyzed the ventilation network, including leakage paths in the entries and flow paths through the gob, for each stage. He then constructed a year-by-year cost curves using the appropriate stage outcomes.

The data for the first scenario shown in Table 6 indicate the results of assuming that no drainage system is in existence and all methane is handled by the ventilation system. The analysis proceeded by following a systematic mining plan with drainage wells implemented about five years ahead of mining and shaft development initiated three years in advance. The net present value basis using a 10% discount factor was used to determine costs and benefits. Coal values and costs did not inflate over the time period of the analysis.

Table 6 Gross Costs and Benefits Assuming No Drainage					
Year	**Miner Production (tons)**	**Longwall Production (tons)**	**Ventilation Costs ($/yr)**	**Development Costs ($/yr)**	**Net Present Value[a] of Gross Profits ($)**
1					0
2					0
3				6,035,600	-4,534,600
4				6,035,600	-4,122,400
5	1,191,400	602,100	440,300		2,709,500
6	877,800	2,076,200	1,409,000		6,731,900
7	877,800	2,076,200	1,435,500		6,106,300
8	877,800	2,076,200	1,669,800		5,441,900
9	877,800	2,076,200	1,669,800		4,947,200
10	877,800	2,076,200	1,477,400		4,571,600
11	877,800	2,076,200	1,459,100		4,162,400
12	877,800	2,076,200	1,643,100		3,725,400
13	877,800	2,076,200	1,713,100		3,366,500
14	877,800	2,076,200	1,590,500		3,092,700
15	877,800	2,076,200	1,484,300		2,837,000
16	725,300	2,076,200	1,539,500		2,533,900
17	438,900	2,076,200	1,643,100		2,226,300
18	438,900	2,076,200	1,604,500		2,030,900
19	438,900	2,076,200	1,400,300		1,879,700
20	438,900	2,076,200	1,400,300		1,708,800
21	12,900	2,076,200	1,479,200		1,485,200
22		2,076,200	1,481,600		1,348,300
23		436,000	323,000		2,560,100
Totals[b]	12,463,200	36,333,500	26,863,400	12,071,200	52,504,500

[a]Net present value based on a 10% discount rate.
[b]Totals may not agree with column values due to rounding.

The figures in Table 6 reveal a net present value of greater than $26 million dollars in ventilation costs for this scenario. This is a very high value, especially considering that no income can be expected from sales of the methane. It would certainly be advantageous using methane drainage in this hypothetical operation to reduce the ventilation costs. To keep the ventilation velocities in the optimal range, the number of main entries is decreased from 21 to 7 while submains are decreased from 9 to 5. In addition, the headgates and tailgate are decreased from 5 entries to 3.

The economic results are shown in Table 7. As can be seen, the net present value of gross profit improves by about $5,800,000. This improved result comes from three sources:

(1) Reduced ventilation costs because of lower amounts of methane handled by the ventilation system.

(2) Decreased production costs resulting from more coal (approximately 5,100,000 tons) being mined by the longwall at $14/ton and less being mined by the continuous miners at $19/ton.

(3) An increase in reserve or tonnage mined (approximately 10,000,000 tons) by eliminating pillars left behind in the mains, submains, and gate entries when these entry sets are downsized. This tonnage is mined by the longwall.

The extra tonnage achieved using this second scenario will be mined in years 24 through 29. This reduces its value to the gross profit figure because of the discount rate. However, all three sources of improvement enable the hypothetical mine to pay about $32,500,000 in drainage costs and improve the gross profit.

It is also useful to look at a third scenario in which the mine is able to achieve a 5% decrease in downtime at its production faces as a result of reducing the methane available in the coal when it is mined. The assumption in this scenario is that the result is an increase in production of 5% from both continuous miner faces and the longwall. As shown in Table 8, the mine life is reduced from 29 years to 28 years, and the net present value of gross profit is increased by $2,100,000.

In the three scenarios presented here, the primary economic advantages achieved are in the areas of reduced ventilation costs, increased coal tonnage, reduced production costs, and decreased downtime. The assumptions made did not consider other possible economic impacts such as improved dust conditions, improved safety, reduced water problems, or enhanced worker comfort. In addition, it was assumed that the methane could not be marketed. However, selling the methane would obviously improve the economics of drainage by a significant amount. Nonetheless, the results show that methane can be economically be drained without a market.

Table 7
Gross Costs and Benefits Assuming 60% Drainage

Year	Miner Production (tons)	Longwall Production (tons)	Ventilation Costs ($/yr)	Development Costs ($/yr)	Drainage Costs ($/yr)	Net Present Value[a] of Gross Profits ($)
1					960,000	-872,700
2					1,050,000	-867,800
3				3,538,100	1,140,000	-3,514,700
4				3,538,100	1,230,000	-3,256,700
5	735,000	1,341,100	300,600		1,310,000	4,452,600
6	385,500	2,128,800	472,000		1,400,000	6,370,800
7	385,500	2,128,800	472,000		1,400,000	5,791,600
8	385,500	2,128,800	558,200		1,400,000	5,224,900
9	385,500	2,128,800	617,000		1,400,000	4,725,000
10	385,500	2,128,800	617,000		1,400,000	4,295,500
11	385,500	2,128,800	569,000		1,400,000	3,921,800
12	385,500	2,128,800	530,900		1,400,000	3,577,400
13	385,500	2,128,800	530,900		1,400,000	3,252,200
14	385,500	2,128,800	624,200		1,400,000	2,932,000
15	385,500	2,128,800	709,600		1,400,000	2,645,000
16	385,500	2,128,800	709,600		1,400,000	2,404,500
17	385,500	2,128,800	657,000		1,40,0000	2,196,300
18	385,500	2,128,800	601,500		1,400,000	2,006,600
19	385,500	2,128,800	601,500		1,400,000	1,824,200
20	298,800	2,128,800	647,200		1,400,000	1,638,700
21	192,800	2,128,800	703,200		1,400,000	1,467,800
22	192,800	2,128,800	703,200		1,400,000	1,334,400
23	192,800	2,128,800	630,900		1,400,000	1,221,200
24	192,800	2,128,800	528,600		738,000	1,197,700
25	119,900	2,128,800	528,600		360,000	1,107,900
26		2,128,800	567,800		180,000	1,001,400
27		2,128,800	632,300		90,000	912,300
28		2,128,800	632,300			835,300
29		1,426,300	416,000			513,300
Totals[b]	7,321,900	51,729,800	14,561,100	7,076,200	32,528,000	58,329,000

[a]Net present value based on a 10% discount rate.
[b]Totals may not agree with column values due to rounding.

Table 8
Gross Costs and Benefits Assuming 60% Drainage and a 5% Downtime Reduction

Year	Miner Production (tons)	Longwall Production (tons)	Ventilation Costs ($/yr)	Development Costs ($/yr)	Drainage Costs ($/yr)	Net Present Value[a] of Gross Profits ($)
1					960,000	-872,700
2					1,050,000	-867,800
3				3,538,100	1,140,000	-3514,700
4				3,538,100	1,230,000	-3,256,700
5	771,800	1,408,100	440,000		1,310,000	4,638,500
6	404,800	2,235,200	547,500		1,482,400	6,652,900
7	404,800	2,2352,00	547,500		1,482,400	6,048,100
8	404,800	2,235,200	547,500		1,482,400	5,498,300
9	404,800	2,235,200	715,800		1,482,400	4,927,100
10	404,800	2,235,200	715,800		1,482,400	4,479,200
11	404,800	2,235,200	715,800		1,482,400	4,072,000
12	404,800	2,235,200	615,900		1,482,400	3,733,600
13	404,800	2,235,200	615,900		1,482,400	3,394,200
14	404,800	2,235,200	615,900		1,482,400	3,085,600
15	404,800	2,235,200	823,200		1,482,400	2,755,500
16	404,800	2,235,200	823,200		1,482,400	2,505,000
17	404,800	2,235,200	823,200		1,482,400	2,277,300
18	404,800	2,235,200	697,700		1,482,400	2,092,800
19	404,800	2,235,200	697,700		1,482,400	1,902,600
20	202,400	2,235,200	816,200		738,000	1,699,500
21	202,400	2,235,200	816,200		360,000	1,529,000
22	202,400	2,235,200	816,200		270,000	1,390,000
23	202,400	2,235,200	816,200		180,000	1,346,800
24	73,100	2,235,200	613,100		90,000	1,270,200
25		2,235,200	613,100			1,156,300
26		2,235,200	613,100			1,058,700
27		2,235,200	613,100			969,300
28		1,147,300	146,700			467,200
Totals[b]	7,321,700	51,729,800	15,688,000	7,076,200	32,528,000	60,437,900

[a]Net present value based on a 10% discount rate.
[b]Totals may not agree with column values due to rounding.

POTENTIAL USES

One of the major decisions facing a mine owner when considering the implementation of a CBM drainage program is the potential use for the gas. The gas is a clean energy resource. However, the location of the mine and the ability to convert the gas into a marketable product may severely test the mine planners' perseverance in finding an economic way of using the gas and producing the accompanying reduction in greenhouse gases. This section will outline some possibilities for the gas whether it is a high-Btu, medium-Btu, or low-Btu product. A list of potential uses has been complied by the USEPA and appears in Table 6. A quick summary of the uses is provided in the paragraphs below.

High-Btu Gas

High-Btu gas is generally defined as having enough heat content to be used in a natural gas pipeline. As shown in Table 9, several potential uses exist for high-Btu gas. If the drainage system provides primarily CH_4 and little in the way of inert gas, the product may be gathered, compressed, and marketed to a pipeline company. This is one of the most desirable options if natural gas pipelines are located near the mine. As shown in Fig. 13, many of the natural gas pipelines are located in the coal mining regions of the U.S. Thus, marketing of methane to a pipeline company would be a very desirable goal.

If pipelines are not readily available or if the pipeline companies are not in the market to buy methane, several other options are available for high-Btu gas. The first of these would be to use the gas as a feedstock to produce ammonia, methanol, or acetic acid. Currently, these chemicals are produced from natural gas, but coalbed methane would be equally useful if it is available in sufficient quantities and if the chemical plants were in a favorable location.

Another potential method of using CBM would be to compress or liquefy it for use in buses, trucks, and automobiles. This implementation has been successfully used in the Ukraine and the Czech Republic and has two primary environmental advantages. First, it reduces the greenhouse gases released from the vehicles as combustion byproducts. Second, it utilizes an energy resource that would be wasted otherwise. The use of CBM in this way requires only that the gas be available in reasonably steady quantities over time and be available close to the transportation system.

Mining companies that are currently harvesting high-Btu gas from mines are relatively few in number. However, the potential economic returns are very high when ideal conditions are available. The evidence of this is that some mining companies achieve greater profits from CBM sales than they do from sales of their coal.

Table 9
Potential Uses for Gas Produced
in Coalbed Methane Drainage Operations

High-Btu Gas (> 950 Btu/scf):

Natural gas pipeline fuel (> 97% CH_4)
Chemical feedstock for ammonia, methanol, and acetic acid production (> 89% CH_4)
Transportation fuel as compressed or liquefied gas

Medium-Btu Gas (300 - 950 Btu/scf):

Spiking with propane or other gases to increase Btu content to pipeline quality
Co-firing with coal in utility and industrial boilers
Fuel for internal combustion engines (> 20% CH_4)
Enrichment through gas processing
Brine water treatment (> 50% CH_4)
Greenhouse heating
Blast furnace use (as a supplement to natural gas)
Production of liquefied gas (> 80% CH_4)
Fuel for thermal dryers in a coal processing plant
Fuel for micro-turbines (> 35% CH_4)
Fuel for heating mine facilities
Fuel for heating mine intake air
Use in fuel cells (> 30% CH_4)

Low-Btu Gas (< 300 Btu/scf):

Use of ventilation air as combustion air in power production (< 1.0% CH_4)
Use of ventilation air as combustion air in I-C engineers or turbines (< 1.0% CH_4)
Conversion of ventilation air into energy using oxidation technologies (< 1.0% CH_4)

Source: USEPA brochures available as part of the Coalbed Methane Outreach Program. For access to these brochures, contact Mr. Karl Schultz, USEPA (6202J), Washington, DC 20460.

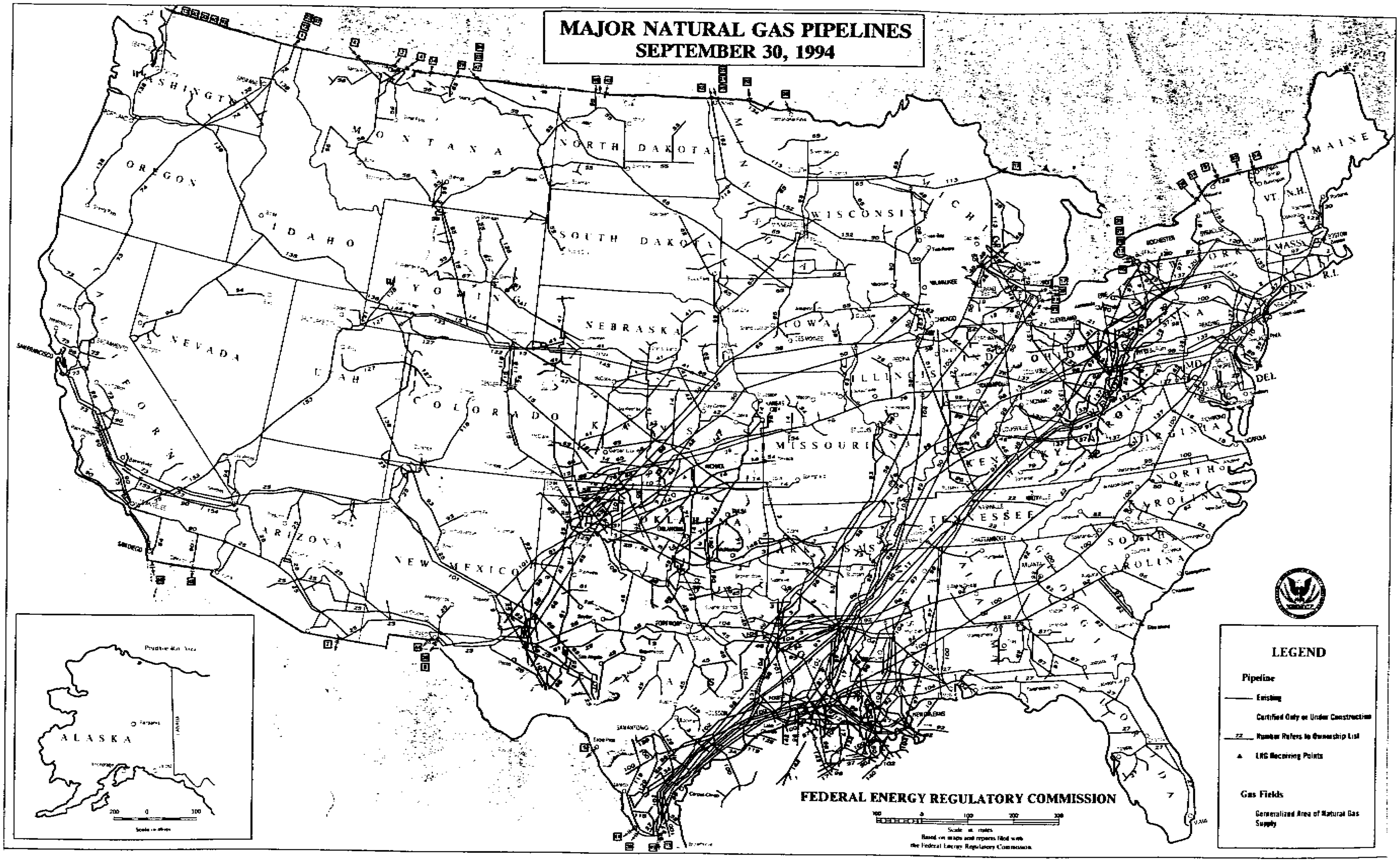

Figure 13. Map of the Major Natural Gas Pipelines of the United States (Federal Energy Regulatory Commission, 1994).

Medium-Btu Gas

Medium-Btu gas refers to CBM gases having 300 to 950 Btu/scf. There are many possible uses for medium-Btu gas as shown by the listing in Table 6. However, it may be more difficult to isolate the most favorable option from the others and to find an economic justification for utilizing the gas. In many cases, however, the economic benefits will make the effort to locate a use worthwhile.

Because of the wide range of Btu values in this category, a variety of possibilities can be found. If the gas is at the high end of the heat content scale, enrichment by blending with a higher-quality gas or spiking of the gas to produce a gas of pipeline quality is possible. Enrichment is the removal of gases like nitrogen, oxygen, and carbon dioxide to improve the heat content of the gas. Spiking is the process of combining another fuel gas (like propane) with the methane to increase the heat content. Spiking will normally be economic only if the supplement gas is available cheaply in the area. In addition, it may not always produce a gas product that is acceptable in a pipeline.

A major and growing use of medium-Btu gas is as a substitute for other fuels in space heating and other applications where natural gas, fuel oil, or coal is normally used. For example, CBM can be used for heating mine facilities, heating mine intake air, heating greenhouses and institutional facilities, as a heat source in a thermal dryer and as a heat source for treating brine water. These applications utilize CBM as the primary fuel in most cases. However, additional uses may be found in which methane is used as a secondary fuel source. These include using methane in coal-fired utility and industrial boilers and as a supplement to natural gas in blast furnaces. Proximity of the CBM source and the end use are the primary requirement for these applications.

Another use for medium-Btu methane is in electric power production. Either internal combustion engines, turbines, or fuel cells can be used in this manner. The electrical power generated can then be used at the mine or be input to the power grid for use elsewhere. The Public Utilities Regulatory Policies Act (PURPA) of 1978 allows a company using certain qualifying waste energy resources for electric power production access to the power grid. This assures a market for the power if it can be produced at an economic cost level.

While the use of medium-Btu CBM does not often offer a mining company as large a return as high-Btu gas, the uses of medium-Btu gas is growing and the related technologies are being rapidly improved. It would thus be a mistake to overlook the uses that are possible for medium-Btu gas. Because many potential applications are available in this category of gas, the mine management must consider many options. However, many of the options may quickly be dismissed upon first inspection and only a few may require careful evaluation.

Low-Btu Gas

Coalbed methane below 300 Btu/scf is released from in many mines throughout the U.S. In most cases, these mines handle methane using ventilation alone and the gas is released into the atmosphere with the exhaust air of the mine. The concentration of methane is below 1%, making it impossible for use as a primary energy source. However, two uses are both possible and reasonable under proper conditions. One is to use the methane by utilizing mine ventilation air as a replacement for combustion air in various energy production facilities. This includes internal combustion engines, turbines, and coal-fired power plants. This has already been done in Australia at two coal mines (Eade, 1996). Another possible use for low-Btu gas is in a thermal oxidizer to produce heat. This converts about 75% of the CH_4 into heat, but has not yet been applied at a mine. Jim Walter Resources has completed a study of the possible use of vent air in gas turbines (Stevenson et al., 1995).

The use of low-Btu gas from mines is still not common because of the relatively low yield of energy compared to the capital costs of utilizing the gas. However, the option of using this waste energy is favorable under the right conditions and should be considered where the mine and a production facility can be located close to each other.

POTENTIAL PROBLEMS

While the drainage and utilization of coalbed methane can be an obvious way for a coal mining company to increase profits while also increasing safety and reducing greenhouse gases, the decision to drain methane from a mine is not always a straightforward one. Several serious problems can make CBM drainage either economically marginal or uneconomic. These problems include uncertain ownership of the methane, difficulty of degassing the coal due to restricted surface access, availability of a gas pipeline, and disposal of water derived from CBM wells. Any of these problems, if present in a decision-making situation, can defeat the economics of a methane drainage project. However, the problems mentioned are not as serious as they have been in the past. This results from the efforts made in the last decade or so to provide solutions. The sections below outline some of the possibilities.

Ownership of Coalbed Methane

The first problem of ownership of the coalbed methane is one that arises due to the lack of definitive mention of coalbed gases when coal and gas rights were separated from the remaining legal rights in the property. In many cases, the gas in the coal seam was not discussed in the legal transaction, either by oversight or because its value was considered to be negligible. Natural gas rights owners would have some logical claim on the CBM if legal ownership was not otherwise established. These conflicting ownership claims were a significant problem for mining companies.

Over the last few decades, the legal issues over who owns the gas have been cleared by a number of court decisions that have been outlined and analyzed by McClanahan (1995). In the analysis, the author indicates that the courts have generally ruled that the coal seam owner also owns the CBM from the seam. In addition, the courts seem to favor allowing the recovery and use of gas that migrates into the seam by the owner of the seam where the gas is recovered. These legal decisions are important to mining companies, both for their positive impact on the safety of mining and for their economic benefits from recovery of coal seam gases. The legal issues already decided have thus been favorable to the mining company.

The second area where the ownership issue has been improved for the mining company is in federal and state legislation to help eliminate unnecessary energy waste and promote environmentally favorable energy use. The federal action was embodied in the National Energy Policy Act of 1992 (EPACT). One of the targets of EPACT is to promote the use of CBM by encouraging its collection and a legal avenue for overcoming ownership issues. The legal detour around ownership problems comes from a forced pooling provision that allows for production of methane in cases of ownership conflicts with royalties paid into an escrow fund. This allows a mining company freedom to extract methane without legal problems. However, the legislation only applies to certain states. The states to which the law applies are listed in McClanahan (1995, p. 529) as Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Tennessee, and West Virginia.

Other states where CBM is a potential energy resource have legislative acts that, in some fashion or another, provide for development of CBM resources. Virginia, Alabama, West Virginia, and Pennsylvania have legislation to encourage the conservation of methane from coal seams. Other states are still subject to ownership issues as they are excluded from the provisions of EPACT. Thus, there may be remaining ownership problems in those states. This and other legal issues have been discussed in the 1995 review by McClanahan. This review should be studied by any company who may have gas ownership questions.

Surface Access

The most logical and cost-effective methods of CBM extraction generally involve vertical wells ahead of mining or gob wells used coincidentally with mining. For this reason, the ability to use the surface to drill wells into the coal seam or seams is an important legal right to the coal miner. In many cases, the mining company secures surface access rights when the coal seam is severed from the remaining property. In these cases, the legal agreement generally would allow the mining company access to the surface to conduct activities that are necessary for the safe mining of the coal. However, in some cases, this may be insufficient to establish drilling sites on the surface. In addition, surface development may make drilling wells or operating a methane recovery operation undesirable.

Pipeline Availability

One of the most economically advantageous uses for CBM gas would ordinarily be injection into a natural gas pipeline. The best CBM projects would thus be those that have a nearby pipeline with excess capacity and a gas distribution company that is anxious to add to its list of suppliers. Fortunately, most areas of the U.S. that have coalbed methane supplies also have a number of natural gas pipelines as shown in Fig. 13. Most Appalachian and Midwest coal mines are relatively close to existing pipelines, but the Rocky Mountain coal deposits have fewer pipelines in their region. For most mines, the proximity of pipelines is thus encouraging to the marketing potential as a gas pipeline product. However, many of the pipelines can be expected to be utilized to capacity. This may pose a constraint on the ability to market the CBM.

Other limitations on the access to a gas pipeline are a result of the quality and quantity variables associated with the gas from a CBM project. Because the gas must be greater than 97% methane and free of deleterious additional gases, it is necessary to carefully monitor the gas quality. This is an important issue when gob gas is mixed with methane from vertical wells. In addition, it may be necessary to carefully plan and systematically develop all the wells to insure that a stable and predictable quantity of methane is capable of being delivered to the pipeline. These measures will help the CBM project managers receive a favorable reception from the gas pipeline operator.

Natural Gas Prices

Because CBM competes most directly with natural gas as an energy source, the market price of natural gas will affect the ability to market methane as a pipeline product. Because of the good fortune of having a plentiful supply of natural gas at present, the economics of CBM is less favorable than it would be if gas prices were higher. However, the current trend in the regulatory and legislative matters is toward use of cleaner burning fuels to reduce atmospheric emissions. This promises to ensure a higher price for natural gas in the future. As a result, the ability to market CBM as a pipeline product or as a local energy source will most likely improve in the future. This should enhance the economic viability of methane degasification projects.

A DECISION MODEL FOR MINING COMPANIES

The decision to implement a CBM degasification project for a mining company may be a difficult one. The primary reason for this is that there are many variables that will play a part in the economics of the decision. The first set of variables deals with the geologic strata and their properties. These variables must be measured to help estimate total gas and its ability to be collected. The second set of variables deals with the mining-related costs. These can normally be determined by mining company personnel. The third area where variation can be of tremendous importance is in the gas extraction, gathering, and marketing area.

Of the three areas mentioned above, the area of gas variables is the most troublesome for a mining company. Unless the company is an energy company with a natural gas producing division, the mining company may wish to seek expert advice from the gas industry personnel to secure good information of gas recovery and marketing economics. One method of doing this would be to seek a gas company as a partner and work together to coordinate the mining and methane extraction processes. Alternately, the mining company can seek help from a consulting firm. A list of such firms is available in the literature on methane development (USEPA, 1996). It may be a tremendous boost in technological and marketing help for a mining company to use one of these two options.

The following pages outline a basic decision-making logic for mining companies when confronted with a potential methane drainage situation. The major elements of the decision-making process are shown in Fig. 14 and a general discussion of the process is provided below. The use of the model may require that a mine or a company alter the overall process to fit a given situation. The description of the elements in the model are provided below. Where appropriate, comments concerning the elements or references are provided.

Model Element	Comments
1	The determination of the gas content of the seam is very important in the overall decision. An excellent reference for methods of determining gas content is McLennan, Schafer, and Pratt (1995). Most coal seams will require considerably more than 100 cubic feet of gas/ton to ensure a favorable decision on drainage. However, studies by Wang (1997) showed gas contents of 200 cubic feet/ton were sometimes economic even if only the mining-related benefits were considered.
2	Determine if delays (stoppages and slowdowns) can be determined at the mine.

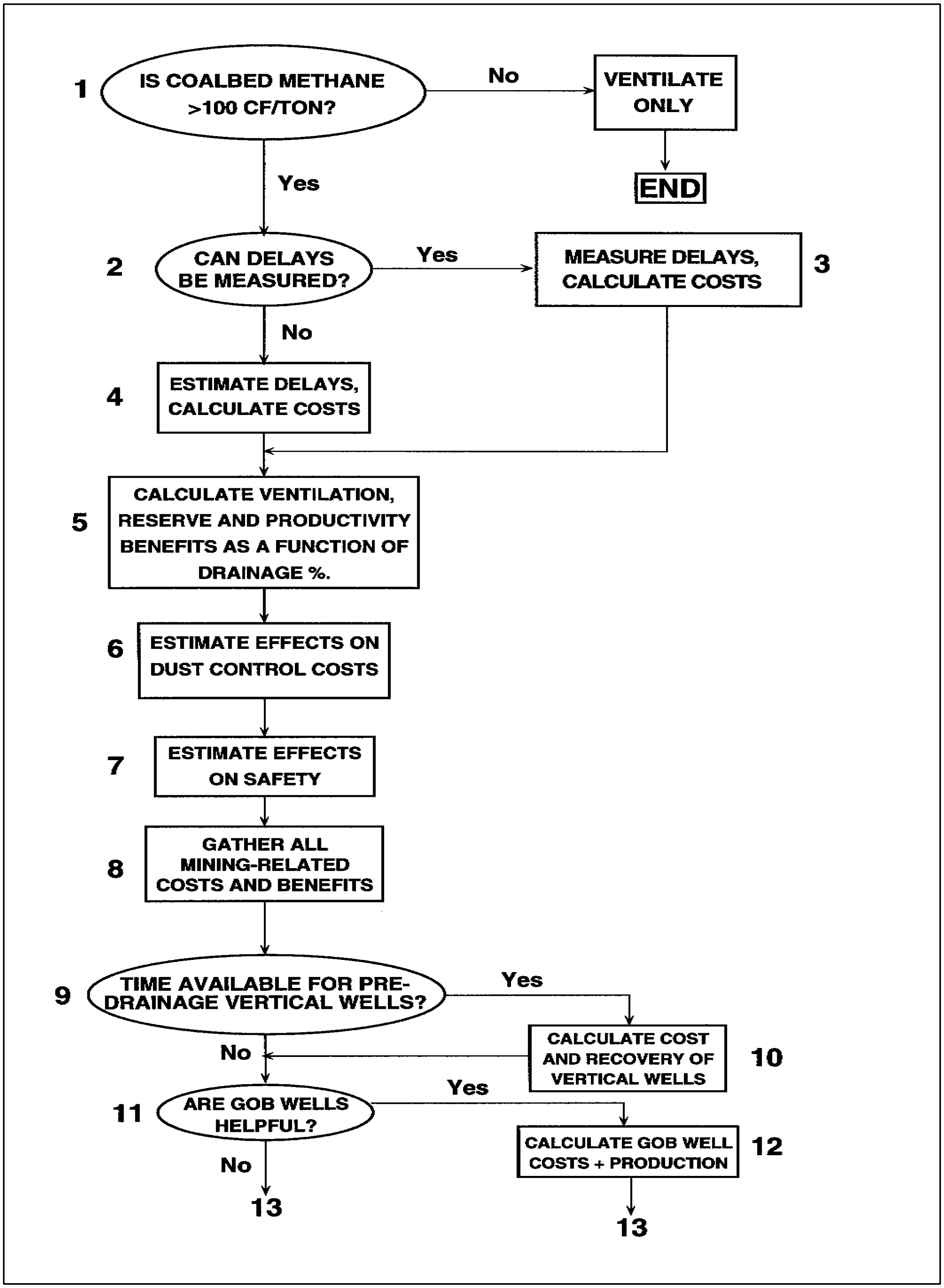

Figure 14. Model for decision making in coalbed methane projects.
(continued on next page)

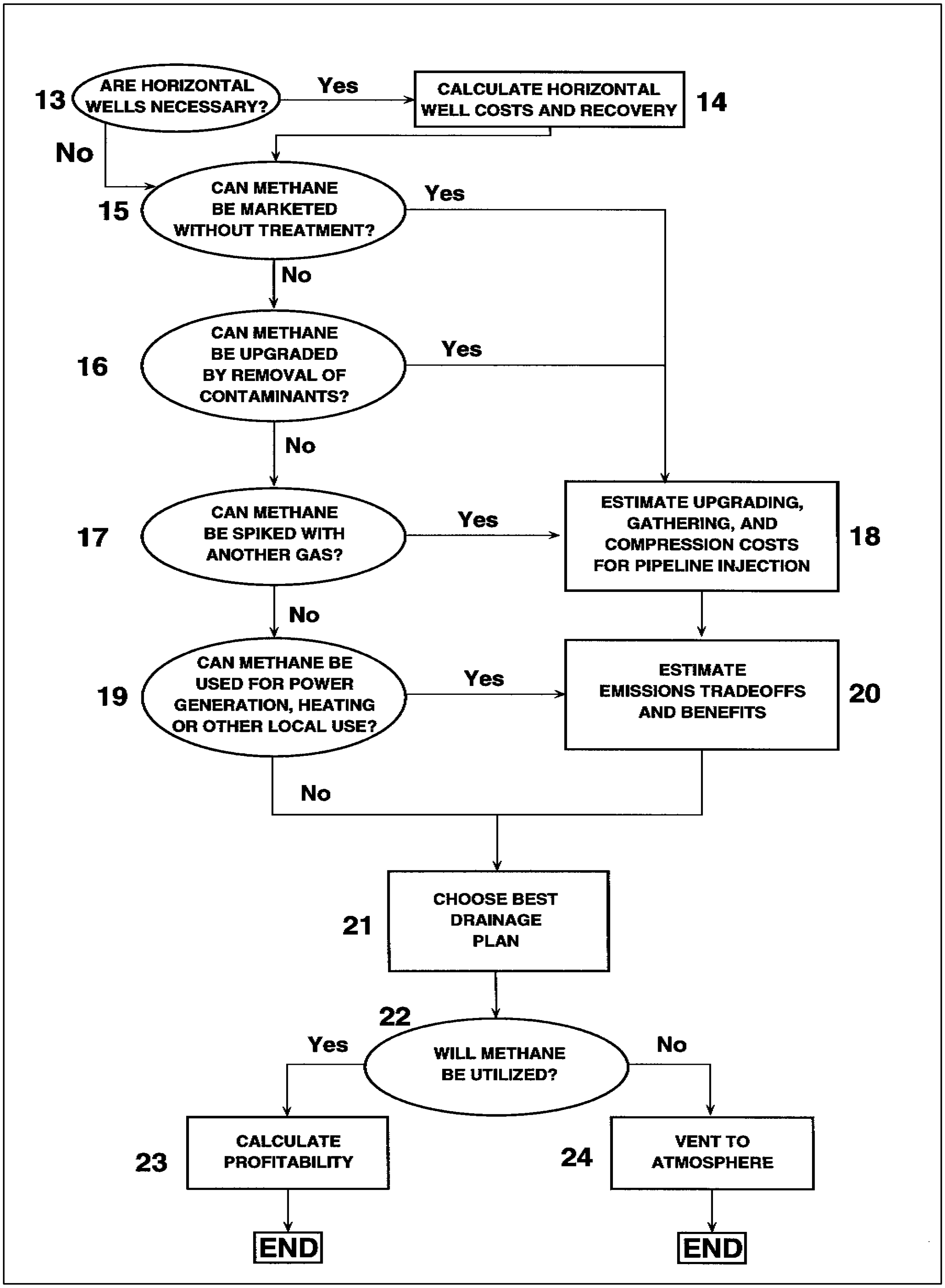

Figure 14. Model for decision making in coalbed methane projects (continued from previous page)

Model Element	Comments
3	Use well established engineering procedures to measure stoppages and slowdowns caused by methane on the mining faces. Stoppages can be determined through foreman reports, but slowdowns will require time studies for accurate measurement. The costs should be determined using proper accounting procedures.
4	Estimation of delays and slowdowns can be accomplished from similar sections in neighboring or similar mines. Costs of downtime must be determined through accounting procedures.
5	Ventilation calculations can be used to estimate ventilation costs. Publications by Kim and Mutmansky (1990), Aul and Ray (1991), and Mutmansky and Wang (1998) may be of help. Reserve and productivity benefits are described earlier in this report.
6	Dust control may be enhanced or worsened by the air volumes chosen. Information on this topic is available in Breuer (1972) and Mundell et al. (1979).
7	The effect on safety and safety-related costs may be difficult to measure. Drainage should clearly benefit safety. Thoughts on this topic may be found in Ely and Bertard (1989) and Mills and Stevenson (1989).
8	Gathering estimates of all mining-related costs is performed in this step. Costs and benefits that have been determined in steps 4 through 7 are combined.
9	Two to seven years are normally required to affect a significant methane recovery percentage from vertical wells.
10	Costs associated with vertical wells can normally be estimated using information from Tables 1 and 2.
11	Gob wells are most helpful in longwall gob areas and are an effective way of reducing methane in longwall operations.
12	Gob well costs can be estimated using Tables 1 and 2.
13	Horizontal or cross-measure wells are normally useful in high-methane mines or mines where surface access is restricted. Normally, they are used as a supplement to vertical or gob wells.
14	Horizontal (or cross-measure) well costs can be estimated from information available through Table 1.
15	The possibility of marketing the methane as a pipeline gas product is the first and most income-producing option. This should be investigated if the gas has more than 90% methane.

Model Element	Comments
16	In some cases, the methane can be cleaned by taking out water vapor, nitrogen, oxygen, and carbon dioxide. Information on these processes and a list of companies with expertise in this area are provided by USEPA (1997).
17	Spiking is the process of adding another gaseous fuel like propane to the methane to increase its Btu value. This may be a viable alternative in certain areas of the country if a low-cost spiking gas is available and if the mix does not violate pipeline gas quality constraints.
18	These costs can be estimated starting with the information in Table 3 and in USEPA (1997).
19	The variety and number of local uses is increasing rapidly. Table 6 provides a list of possible uses. The use of medium-Btu methane should increase significantly in the future.
20	The use of greenhouse gas credits as a tool in marketing methane from a coal mine should be investigated. Some possible avenues of using this benefit are available in Harvey (1998) and in Zaborowski (1998).
21	The best drainage plan will be a function of the percentages of methane drained, the mining-related benefits, and the marketing revenues for each feasible option.
22	The use of the methane is dependent on the costs versus the income to be derived from its use. If the methane can be mined for the mining-related benefits alone, the costs of extracting the CBM are sunken costs and only the marketing costs should be considered at this point.
23	If the methane is to be utilized, this implies that the utilization will result in benefits or profitability. This value is determined at this point.
24	If the methane cannot be marketed at a profit, it is economically justifiable to vent the gas to the atmosphere. However, when the gas is vented, the mining company should periodically reinvestigate possible uses as the technologies of methane utilization are rapidly advancing.

While the process may at times involve other considerations, the model presented above leads the decision-maker through most of the variables and elements that must be investigated to ensure a correct economic outcome.

CONCLUSIONS

The decision concerning whether or not to implement a CBM degasification system at an underground coal mine is dependent on many variables. It is therefore important to have a framework for making decisions. This publication provides the framework or at least most of its elements. In preparing this report, the following conclusions were apparent regarding the use of coalbed methane drainage:

The political and technological climate for CBM projects is favorable. The technology is improving at the same time as the environmental concerns are growing.

Any mining company experiencing delays or shutdowns in their mining sections due to high methane concentrations is a prime target for a drainage system because of high costs associated with section production losses.

The mining-related economic benefits of a methane degasification system can be considerable and will often justify the use of drainage without the economic benefit of having a market for the gas. Studies have shown that 400 cubic feet of methane/ton of coal will often result in a drainage system being economic without a market for the gas.

Pipeline-quality gas is achievable in many coals mines, either by choosing the correct drainage method, by spiking the methane with another gas, or by cleaning up the gas generated.

Medium-Btu (300 to 950 Btu/scf) gas usage technology is improving rapidly. Mining companies should be monitoring this area of energy use so they can adopt the technology as it becomes more economically favorable.

The use of greenhouse gas credits resulting from methane drainage can be a great benefit in marketing coal. Mining companies can use this to their advantage.

Natural gas prices, while modest at present, are projected in government reports to rise in the future. This will help secure a more favorable market for CBM.

Partnerships between gas and coal mining companies are a logical method of enhancing the overall coal and gas recovery operations.

The future for the coalbed methane industry is quite favorable. When CBM is used as an energy source rather than vented to the atmosphere, everyone gains something. It is, therefore, a goal that is worthy of some effort on the part of mine management.

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